Wind Integration in Estonia

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Preface

This master thesis was written during the spring semester of the academic year 2009-2010 in cooperation with EA A/S, Elering OU and Risø DTU. The report was written over a period of five months, from February 1st to June 30th 2010.

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Altiparmakis Argyrios – s081366

Introduction

During the past two decades, wind power capacity has increased significantly in many countries. This rising wind penetration in electricity grids has lead to a lot of research on the impacts of increasing wind capacity for the power system. While wind power is greeted as a clean energy source, limiting CO_2 emissions, its growth has been accompanied with concerns over its effect on power system reliability or its contribution to grid safety.

One of the latest countries to plan an expansion of its installed wind power capacity is Estonia. The Estonian power system is rather unique due to its reliance on a fuel seldom used anywhere else (oil shale) and the fact that it was designed and constructed to serve the needs of a much wider area originally. Before installing further wind capacity, Elering OU, the Estonian TSO initiated this report in order to look deeper into issues of wind power integration in the region.

One of the main issues with wind power is whether it can contribute to any degree to capacity adequacy. The intermittent nature of wind means it may not produce any output when demand is high, thus offering no capacity benefits. This is not always the case though and there are times of high demand during which wind power contributes to system adequacy. As such, wind power's improvement of system reliability needs to be measured and quantified. This is done through the calculation of **capacity credit**, which is an index measuring the contribution of any power plant (for example wind farm's) to system security. In this case, Estonia already has plentiful capacity and thus the question is whether wind power can provide any benefit in that respect.

A second aspect of wind power that needs to be studied in close relation to the first is the effect wind's unpredictability and variability have on the system operator's planning. Electricity is a unique product due to the fact that demand must always meet supply exactly. As such, transmission system operators (TSOs) plan days to hours in advance the schedule of power plants that need to be activated to serve demand. Not doing so would create technical problems to the system that could lead to blackouts and significant costs to the afflicted parties. Wind power tends to complicate the problem of optimized dispatch of power plants due to its unpredictability until very close to the hour of the event. This has lead to the development of advanced wind forecasting models that can with a certain degree of accuracy predict the wind power production up to a day or two before. This report takes a look at how forecasting can improve with larger wind networks and compares the forecasting capabilities of different systems in order to examine the accuracy with which the Estonian TSO can forecast wind power in the future.

Assuming varying degrees of accuracy, the impact of wind power on the amount of reserves, primary, secondary or tertiary is examined. Inaccuracies in load forecasting already force TSO's to keep a certain amount of reserves and in this report it will be examined how wind unpredictability compounds the issue.

1. The Estonian Power System

1.1 Description, features and composition

The Estonian power system is a fairly unique power system due to its reliance on a fuel seldom used in other places in the world, oil shale. Power plants utilizing oil shale as the primary fuel provide almost 95% of the Estonian electricity supply [1]. Electricity consumption in Estonia was approximately 8 GWh in 2009. Estonia is the relatively largest producer of electricity from oil shale and only China has comparable absolute oil shale power plant capacity [2]. Below a historical graph showing oil shale mined in various places in the world in the past 130 years.

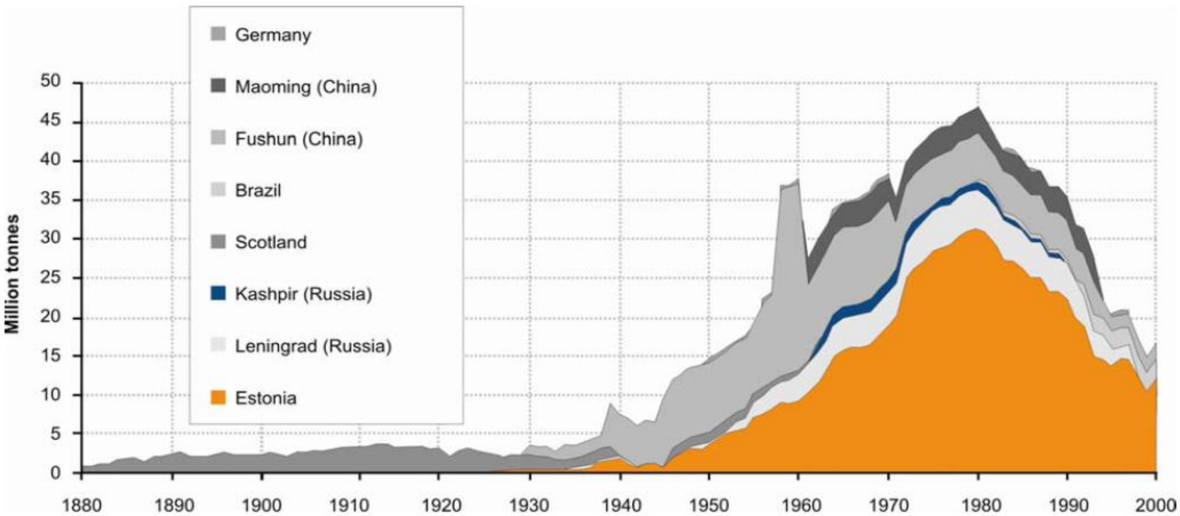

Figure 1.1: Oil shale mined from deposits in various locations, World Energy Council [2]

A table showing the share of each fuel type in power production is provided in table 1.1 below. Additionally, the projected capacity for 2013 is shown on the rightmost column, listing the forecasted growth of the Estonian power system according to Elering. The numbers provided are approximations, as some of the data is confidential:

Fuel Type	Capacity 2009 (MW)	Capacity 2013 (MW)
Oil Shale	2000	1950
Natural Gas	160	500
Biomass	0	80
Wind	140	320
Total	2300	2850

Table 1.1: Estonian power plant fuel data for 2009 & 2013

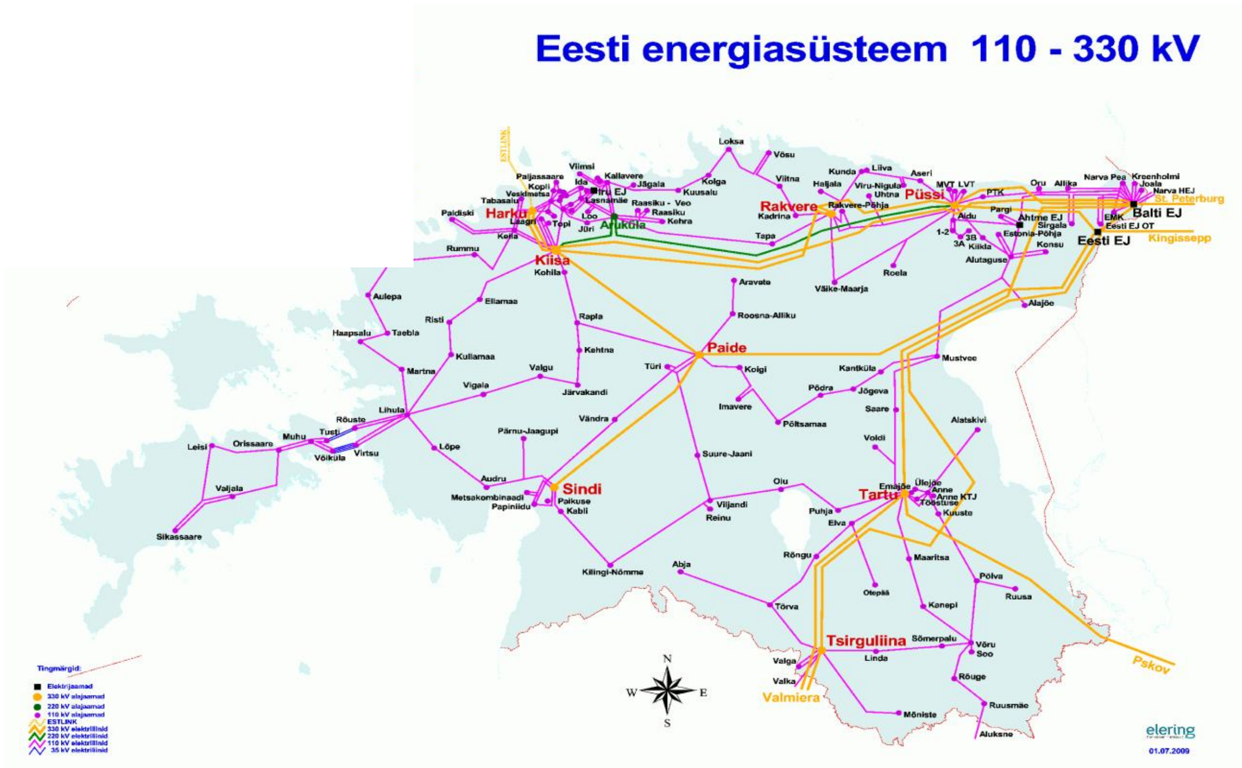

Figure 1.2: Estonian Transmission Map, Elering [1]

The oil shale power plants and the Estonian system in general have been designed during the Soviet Union era with the purpose of serving the northwestern USSR's electricity needs [1]. As such, the capacity currently existing in the Estonian power system exceeds the observed peak demand significantly, by a factor of almost 800 MW (peak demand in 2007 was 1553 MW while the total supply is now almost 2300 MW). However the necessity to adhere to European Union rules for the share of renewable energy in the system and the Estonian government's wish to reduce CO_2 emissions has led to an effort to introduce and integrate wind power into the Estonian power system which will replace some of the outdated oil shale power plants built in the 1970's. It is expected that by 2025 most of the oil shale power plants operating now will be out of use and replaced by newer ones/natural gas/wind resources. The size of the wind power introduced into the system is an issue of extended debate in Estonia, and different plans incorporate wind of as little as 300 MW to as much as 3-4 GW.

Most of the power production in Estonia is happening in the area of Narva in the northeastern border with Russia, where the oil shale power plants are located. The centralized nature of the Estonian power system and the remote location of its current power plants add another challenge to the integration of wind power, as a distribution and transmission infrastructure has to be built also in places where wind power will be most profitable. These places tend to be in the western part of the country, away from where the current majority of power production is taking place.

Most of the oil shale power plants are condensing steam engine power plants, while the natural gas power plants are back-pressure CHP and most of the planned biomass power plants will be extraction CHP power plants. The back pressure CHP plants don't allow for much flexibility in determining the heat:electricity ratio and thus reduce system flexibility from which wind power could benefit. The CHP plants cover approximately 30% of the heating demand (particularly in the capital whose heat is for a big part provided by the Iru CHP plant) while an extended and developed network of district heating based on boilers operating with natural gas is covering the rest [1].

1.2 Interconnections and market

The Estonian power system has interconnections with all its neighbors, sharing power and transmitting electricity to Latvia, Russia and through the newest interconnection to Finland and consequently the Nordic grid. Maps of the Nordic and Baltic grids are shown below:

Figure 1.3: Nordic Grid Transmission Map [1]

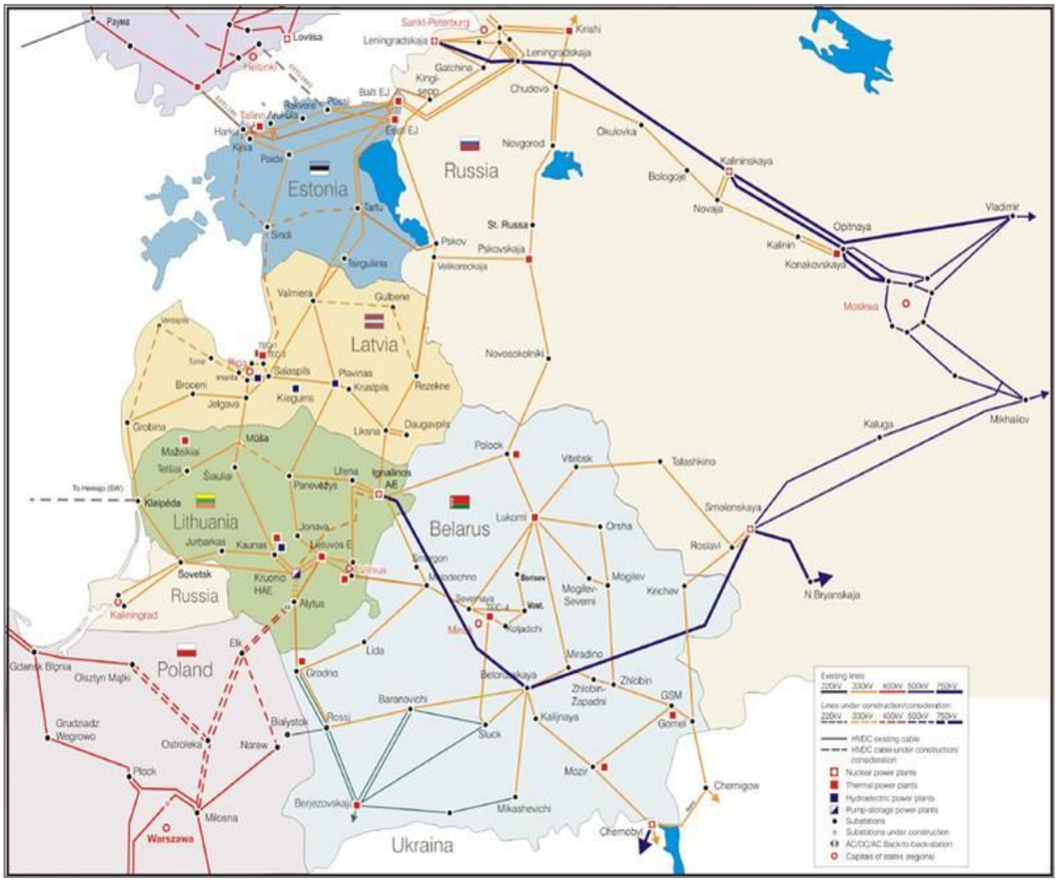

Figure 1.4: Baltic Grid Transmission Map [1]

Electricity trade with Russia is made on the basis of a bilateral contract and is limited to 500 MW for the entire Baltic region, from which only a part can be used by each Baltic country. As seen on the map, the interconnection flows through Belarus. Sometimes the possibility for transmitting electricity through those interconnections is limited by Russian electricity loop flows heading to the northwestern part of the country through the Baltic countries and Belarus.

It is usual to not use the entire thermal capacity of the lines, as the interconnections are mostly used for reliability purposes and are there partially to eliminate faults that occur in another area in the region. The Baltic countries essentially share ancillary services like frequency control and maintaining mandatory reserve levels through the use of the interconnectors.

The Estonian grid has also been recently linked to the Finnish one with the addition of an HVDC line named ‘Estlink 1’. It has a capacity of 350 MW and its importance lies in the fact that it operates based on market rules contrary to the interconnectors to the Baltic countries and Russia which are operated based on bilateral agreements with the main purpose being the handling of contingencies. As such, it is expected that Estlink 1, and its 650 MW extension Estlink 2 scheduled to begin operating by 2014, will play a major role in wind power integration in Estonia, as it allows for increased system flexibility which is crucial in systems with high wind penetration.

Specifically, the rapid fluctuations of wind require increased level of up and down regulation which can be better provided in a system with larger and more extended interconnections through importing and exporting electricity. Imbalances and contingencies, as well as wind curtailment are less likely to occur in such a system. Furthermore, it means less wind will have to be curtailed and thus less revenues will be lost by wind producers. In a system without those interconnections limitations in the operation of thermal units such as minimum operating ranges and long start up times would limit the possibilities for down regulation and lead to wind curtailment, damaging the prospects of wind power development.

Further reforms of the energy sector have helped the Estonian system prepare for the introduction of large quantities of wind power. The main Estonian power providers were basing their operations based on bilateral contracts, but after April 2010 Estonia joined the Nord Pool spot market and is expected to be followed by Latvia and Lithuania in 2011, in an effort to integrate the Baltic/Nordic grids into a large electricity trading market covering the entire north Europe area [1].

2. Capacity Credit

2.1 Theory

One of the major concerns of a power system operator is system adequacy. System adequacy is considered sufficient if the installed power capacity is enough to meet the demand from customers. System adequacy has been a problem in a lot of (particularly developing) countries where frequent outages of the system due to excess demand are common. An important issue of research in the field of energy has been how to quantify and measure the contribution of a specific plant to system adequacy [3], [4]. An examination and implementation of some of the proposed methods is one of the objectives of this study.

The introduction of high amounts of wind power into an energy system since 1980 when wind power started developing rapidly has raised questions about its contribution to adequacy in system operation. Due to its intermittent nature it has been assumed that wind power additions pose a threat to system reliability. This is mostly due to the fear that wind power can abruptly cease to provide energy in the event of a storm or some other disturbance, forcing the system to face a significant and sudden outage.
However this is not entirely true. Both the Danish experience with high penetration of wind power into the energy system and calculations for the system of Estonia provided below show that sudden changes in wind power production are ultimately rare and only important when wanting to plan on a 3 hours or more horizon [5], [1].

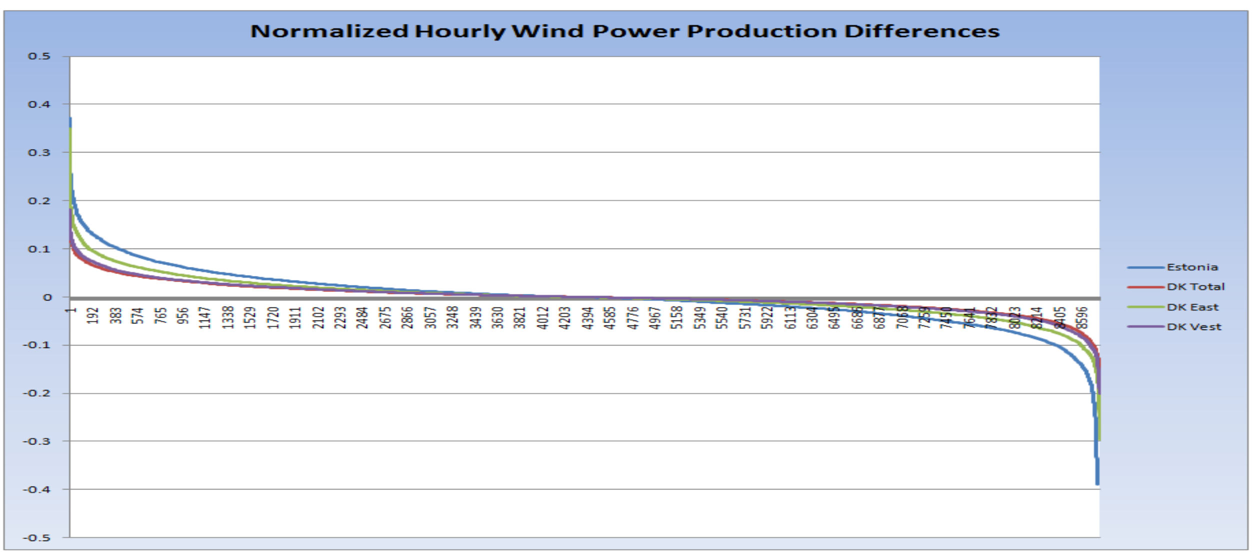

Figure 2.1: Hourly Wind Production Changes for Estonia and Denmark

However, due to the belief that wind power acts as a threat rather than a benefit to the system, its potential to contribute to system reliability and adequacy has often been ignored or overlooked. However, a correct incorporation of wind power into system reliability indices can show that there is potential for it to contribute positively to it under certain circumstances. The approach taken by most TSO's up to this day is to assume that due to the stochastic nature of wind, it carries no capacity value for the system. However it is more probable than not that at any given moment there will be a wind power output and as such wind power will contribute to sharing the burden of serving the load. Quantifying this contribution would greatly facilitate planning and allow TSO's to avoid overcapacity and the costs associated with it.

The first question to be raised is what kind of reliability index is appropriate to estimate the system's risk of shedding load. An established and well known method to do so is by determining the **'Loss of Load Probability'** (LOLP) [4] which is fundamentally either a percentage showing the chance of the system being unable to match a certain load value or a number of days per year (or 10 years) where load has to be shed because supply is unable to meet demand.

The next question that needs to be answered is if the installed capacity of wind power is equivalent to adding thermal capacity to the system which would reduce the chance that load would have to be shed (reduce the LOLP). In current theory, the **capacity credit** is the amount the load can be increased while the reliability of the system remains the same when a new unit is introduced into the system. There are different methods used in the calculation of this quantity but in any case it is a good estimate of whether a new unit increases system adequacy in a meaningful way.

An issue when dealing with LOLP calculations is the stochastic nature of the wind. While a normal thermal unit can be accurately simulated by a binary variable (either 'on' - producing at rated output- or 'off') a wind power farm is actually producing a variable amount of power between zero and its rated output. This has to be incorporated into the LOLP calculations in an appropriate way which is one of the issues discussed in the following chapters.

2.2 Theoretical approaches to capacity credit calculations

The loss of load probability is a central piece to capacity credit calculations and signifies the probability that load will surpass the total generation capacity. The outages of the power stations need to be added to the load. In essence, LOLP is defined by the following formula,

$$LOLP = \frac{\sum_{t|(L_t+O_t-G_t>0)} 1}{T}$$

where L signifies the load, O the outages and G the capacity of all the power stations in the system. The reason load may be shed in a power system is that not every power station has a reliability of 100%. As such, even if the system's capacity exceeds the peak load requirements, there is a chance that failures in operation of one or several power stations might lead to a loss of load situation. The chance of failure of a power plant is termed as the ***forced outage rate*** (***FOR***) and is usually in the 5-15% range for conventional thermal power plants, depending on age, type of fuel and other characteristics.
LOLP is in essence the probability that the system load will exceed the supply. To determine this, the most important parameter is the **Forced Outage Rate** (FOR) of each unit of the power system. The FOR's formula is shown below:

$$FOR = \frac{Time\ the\ unit\ is\ unavailable}{Time\ the\ units\ is\ available + Time\ the\ unit\ is\ unavailable}$$

Essentially, as previously determined, FOR is the unavailability rate of a unit. It is very specific for each type of unit and can be used to determine the chance that at any given time a power unit will be online or offline.

Using the forced outage rate, every power plant can be modeled mathematically as a unit with an 'on' or 'off' situation with the equivalent probability of each situation being equal to 1-FOR and FOR respectively.

In order to assess the LOLP, all that is required is the probability distribution of the load minus the outages (or *equivalent load* all together). Once that is known, the probability of loss of load is simply the point in the distribution for which the equivalent load becomes higher than the total generation capacity. To put this in mathematical terms, the LOLP for k stations is simply [3]:

$$LOLP_k = P\left(E_k > \sum_1^k G_k\right) = F_{E_k}\left(\sum_1^k G_k\right) \text{ [1]}$$

$where\ E_k$ is the equivalent load, G_g the total capacity including plant k

and F_{Ek} is the cumulative probability distribution of the equivalent load, which in turn is provided for the k^{th} power station by the following formula [3]:

$$F_{E_k}(x) = (1 - FOR_k) * F_{E_{k-1}}(x) + (FOR_k) * F_{E_{k-1}}(x - G_k) \text{ [2]}$$

$$where\ x = \sum_1^k G_k$$

The initial input to this formula is the load duration curve, which provides the $F_0(x)$distribution. Then the capacity of each power plant is added until all of them are accounted for. The LOLP is then given by the $F_{E_k}(x)$ corresponding to x equal to the amount of generation capacity existing in the system. This probability distribution calculates the probability that for a given amount of capacity x, the load will surpass the generation.

Alternatively, what can be calculated is the available capacity probability distribution, which is simply the probability that a certain level of capacity will be obtained. This is called as the level of 'supply reliability' and shouldn't be confused with LOLP. LOLP concerns the actual supply reliability while this probability is a parameter that isn't related to the system performance and does not take load levels under consideration. The formula for this method of calculation is the following [6]:

$$S_k(x) = S_{k-1}(x) * FOR_k + S_{k-1}(x - G_k) * (1 - FOR_k) \text{ [3]}$$

In this study, it is important to calculate the impact of wind on LOLP, in order to calculate its impact on capacity credit. Since wind is a stochastic variable that cannot be accurately represented in a probabilistic way like a normal power station, wind and load will be added to provide ***the net load probability distribution*** [3]**,** [4]. This will be compared to the results of LOLP for the equivalent load distribution used previously for each method of capacity credit calculation, in order to assess the wind's impact.

There are a number of ways to calculate capacity credit for wind. The most importanqt ones are described and listed below. The basic premise for most of the methodologies is simply comparing the effect wind farms versus a conventional power plant would have on the loss of load probability and consequently their relative capacity credit.

A. Equivalent firm capacity

This method calculates the amount of extra capacity a fictitious 100% reliable unit would account for compared to the unit that is the object of study. Equivalent firm capacity is defined as the capacity of that 100% reliable unit that will provide the same LOLP decrease as the unit studied. Consequently, to implement this method the following steps should be followed:

a) LOLP with the studied unit (in this case the wind farm) should be calculated.
b) The equivalent load duration (ELC) curve without the studied unit ($F_{E_{k-1}}(x)$) should be calculated.
c) The point on the $F_{E_{k-1}}(x)$ ELC for which the LOLP of the system is equal to the LOLP with the studied unit should be found.
d) Finally, the total capacity of the system (without the wind) should be subtracted from this number.

What this method achieves is providing an idea of how much more capacity is gained by adding a 100% reliable unit to the system compared with adding x MW of wind or other kind of capacity. The formula for the equivalent firm capacity is provided below [3]:

$$C_{EFC} = F_{E_{k-1}}^{-1}\left(LOLP_g\right) - \sum_{1}^{k-1} G_k \ [4]$$

$$LOLP_g = F_{E_k}(\sum_{g=1}^{k} G_g)$$

In this particular case, the $F_{E_{k-1}}(x)$ will be the equivalent load duration curve while $F_{E_k}(x)$ will be the equivalent net load duration curve.

B. Equivalent conventional power plant

This method is similar to the equivalent firm capacity method, only instead of a fictitious 100% reliable power plant, the extra capacity added to the system due to wind is compared to a power plant with an availability close to the one which is typical for this power system configuration. The formula for calculating the equivalent conventional power plant capacity is provided below [3]:

$$C_{ECC} = F_{E_{k-1}}^{-1}\left(\frac{LOLP_g - (1 - p_{ECC}) * F_{E_{k-1}}^{-1}\left(\sum_1^k G_k\right)}{p_{ECC}}\right) - \sum_1^k G_k \text{ [5]}$$

Where P_{ECC} is the availability (1-FOR) of the conventional power plant.

C. Load Carrying Capability

The principle behind this method is to calculate how much the load on a system with wind power can increase before it yields the same LOLP as the system without wind. The addition of wind caused the LOLP to decrease by a certain amount as it will be seen later on and the question is how much additional load this system could handle before it reaches the LOLP of the system excluding wind. The new ELDC produced will be shifted to the right compared to the one without the additional load. The formula utilized for the calculation of the equivalent load carrying capacity is showcased below [3]:

$$C_{ELCC} = \sum_1^k G_k - F_{E_k}^{-1}\left(LOLP_{g-1}\right) \text{ [6]}$$

D. Secured or Guaranteed Capacity

Another way to calculate the reliability of the system would be to find the capacity outage table, i.e. the probability of every state of supply according to the FOR of the thermal power plants. Calculating the capacity outage table becomes quite a complicated task however, as with 16 power plants there are 2^16 states. Even if an algorithm was developed to show all the states and their probability of occurring the information would be too cluttered as different states would be only a few MWs apart and thus not very interesting to study. A faster and more resource friendly way to calculate guaranteed capacity is using a recursive convolution formula [3]. As a start, the probability of not serving the load x at any time is

$$R_k(x) = P(\Sigma s_i < x), where\ s\ are\ the\ outputs\ of\ the\ thermal\ units$$

For all load values lower than the capacity of the first unit, this is equal to the FOR of that unit, as it is assumed the unit is producing at full rated output whenever it is operating.

Unlike the previous methods, this one doesn't involve the load duration curve at all and doesn't take the load levels under consideration. It only calculates the probability of a certain amount of capacity being available or not, according to the levels of existing generation capacity in the system.

Instead of convolution formula (2) which required the load levels as an initial input, in this method convolution formula (3), shown below, is used which only includes the available capacity duration curve.

$$S_k(x) = S_{k-1}(x) * FOR_k + S_{k-1}(x - G_k) * (1 - FOR_k) \ [3]$$

This convolution formula provides the probability that a certain capacity level will be available to the system according to the FOR of the units being available. Usually when implementing this method it is desired to know how much capacity can be reliably expected to be available at an arbitrary probability level typically between 95-99%.

Using this method, the capacity credit would be defined as the difference in secured capacity before and after the addition of an extra unit and the formula for the determination of that is shown below:

$$C_{GC} = S_k^{-1}(\rho) - S_{k-1}^{-1}(\rho) \ [7]$$

Where ρ is the “level of supply” reliability, i.e. the arbitrarily chosen probability level for which at least a certain amount of capacity will be available.

This method’s accuracy is compromised by the fact that it is a simple iterative method that doesn’t take under consideration the load levels and the specific circumstances of the system at hand. This is countered by the fact that it requires little computational work compared to the methods involving ELDC and LOLP. However, in systems like the Estonian with lots of capacity exceeding the actual peak demand by a substantial amount this method is in danger of overestimating the contribution of wind or other power plants to the capacity adequacy of the system. This will become more evident after the calculations are completed.

2.3 LOLP & Capacity Credit Calculation

The Estonian system consists of 16 units, not including wind power and interconnections. Table 2.1 below shows a list of all the Estonian units along with their respective forced outage rates and type of fuel used [1]:

Name	Installed capacity, MW	Fuel	FOR
Narva PP		Oil shale	
EEJ1	160	Oil shale	13.25
EEJ2	160	Oil shale	13.25
EEJ3	160	Oil shale	13.25
EEJ4	160	Oil shale	13.25
EEJ5	170	Oil shale	13.25
EEJ6	170	Oil shale	13.25
EEJ7	160	Oil shale	13.25
EEJ8	190	Oil shale	13.25
BEJ9	190	Oil shale	13.25
BEJ10	160	Oil shale	13.25
BEJ11	190	Oil shale	13.25
BEJ12	160	Oil shale	13.25
Iru CHP	90	Gas	8.73
	80	Gas	8.73
Ahtme CHP	30	Oil shale	13.25
Kohtla-Järve CHP	50	Gas, oil shale	8.73
Total	2240		

Table 2.1: Estonian Power Plants installed by 2009

As it can be seen, the Forced Outage Rates of the Estonian power units are fairly high. However there is a significant overcapacity when compared to the load the Estonian system is called upon to serve. This can be noticed when looking at the Load-Duration Curve for 2009 shown below, where it can be seen that there's only a small amount of time that load demand exceeds 1500 MW, while overall capacity of thermal units is 2240 MW. Also, the Net Load duration curve is shown, that is a curve of the load deducting the wind. As can be seen, the 133 MW of wind installed do not particularly affect the load duration curve. Specifically, the peak load is reduced by 30 MW (from 1510 MW to 1480 MW) and the total amount of energy consumed from 7806 GWh to 7634 GWh (a difference of 162 GWh which is the annual wind production).

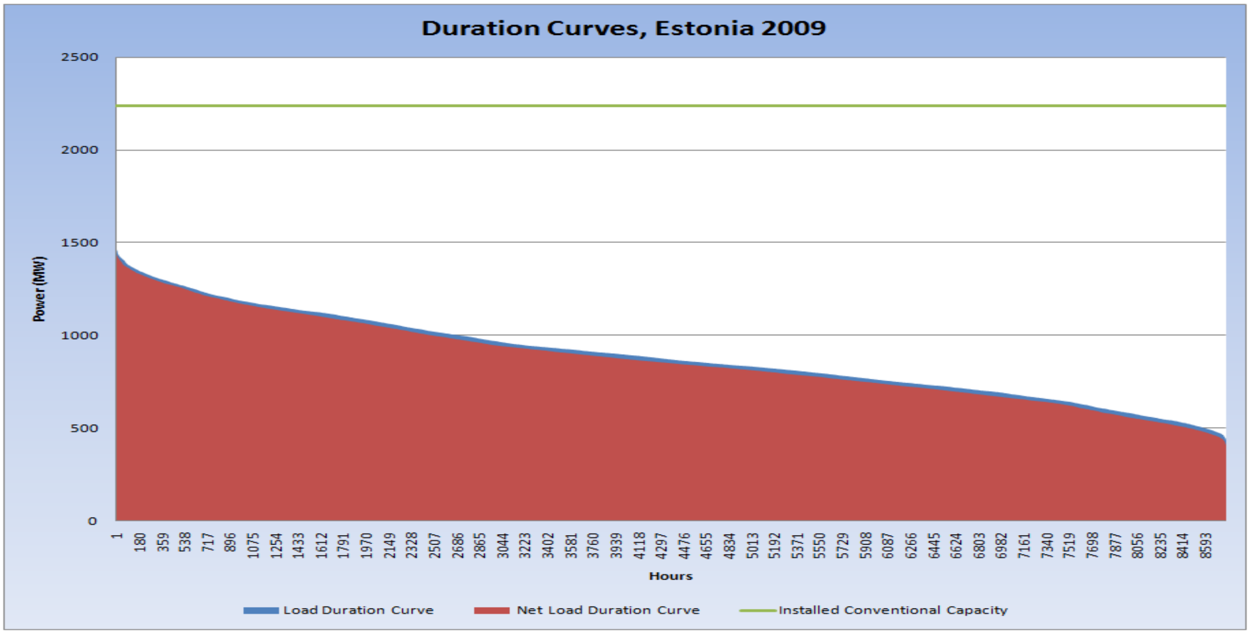

Figure 2.2 Load and Net Load duration curves, Estonia 2009

To start calculating the LOLP and subsequently the capacity credit of wind power, the equivalent load duration curve must be created first, for a system with no generators. Using the load time series provided by the Estonian TSO, the equivalent load duration curve, split into intervals of 80 MW can be seen below:

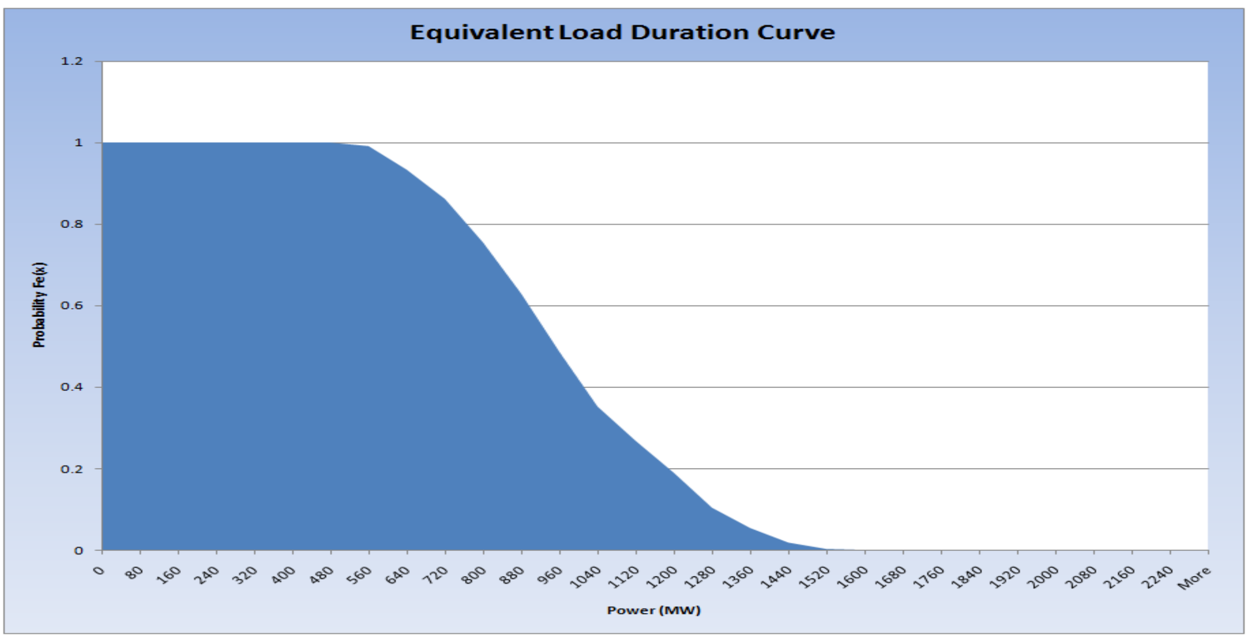

Figure 2.3: Equivalent Load Duration Curve, Estonia 2009

To construct this chart, the load time series were sorted according to the size of their values. Afterwards, a histogram was created showing the frequency of observed energy values for hourly intervals of load. The histogram was split into intervals of 80 MW and its results can be seen in figure 2.4:

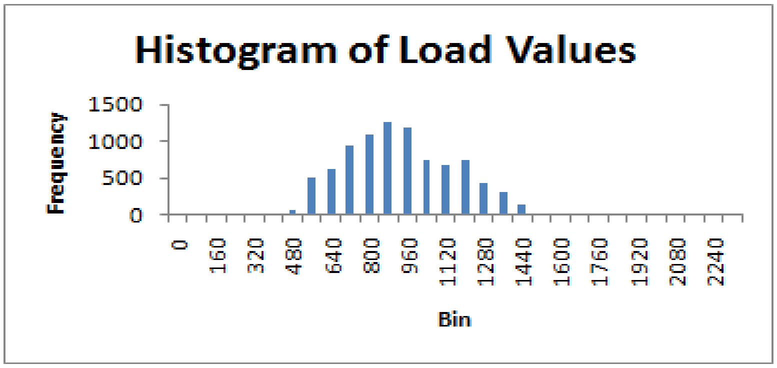

Figure 2.4: Load Levels Histogram, Estonia 2009

To determine the probability that the load will exceed a specific value, the amount of observations in each bracket was divided with the total number of observations. For easing the calculations, it was assumed all values below 480 MW were equal to 480 MW and as such the load had a probability of 1 to be above that number. Afterwards, the cumulative probability for the load being above a certain bracket was calculated and the final results are shown in table 2.2 below:

Bracket	# of observations	Probability f(x)	Cumulative Probability F(x)
0	0	0	1
80	0	0	1
160	0	0	1
240	0	0	1
320	0	0	1
400	0	0	1
480	76	0.00867679	1
560	508	0.05799749	0.99132321
640	628	0.07169768	0.93332572
720	937	0.10697568	0.86162804
800	1100	0.12558511	0.75465236
880	1250	0.14271036	0.62906725
960	1177	0.13437607	0.48635689
1040	739	0.08437036	0.35198082
1120	686	0.07831944	0.26761046
1200	751	0.08574038	0.18929101
1280	436	0.04977737	0.10355063
1360	314	0.03584884	0.05377326
1440	137	0.01564105	0.01792442
1520	20	0.00228337	0.00228337
1600	0	0	0
1680	0	0	0
More	0	0	0

Table 2.2: Probability Table of Load Levels for Estonian Power System

The column to the right is essentially the equivalent load probability distribution $F_0(x)$ on which the convolution formula [2] will be based. It shows the cumulative probability of the load exceeding a specific value before any generators are added to the system.

The next step to calculate the LOLP is to use formula [2] to calculate the probability of loss of load for a specific amount of generation. An example of the use of the formula is provided below for the first power station, an oil shale station with a 13.75% FOR.

$$F_1(x) = F_0(x) * (1 - FOR) + F_0(x - 80) * FOR, \qquad x\ is\ the\ load$$
$$F_1(x) = 1 * (1 - 0.1325) + 1 * 0.1325 = 1, \qquad 0 \leq x < 80$$
$$F_1(x) = 1 * (1 - 0.1325) + 1 * 0.1325 = 1, \qquad 80 \leq x < 160$$
$$\dots$$
$$F_1(x) = 0.933326 * (1 - 0.1325) + 0.991323 * 0.1325 = 0.938339, \qquad 560 \leq x < 640\ and\ so\ on$$

The formula provides the loss of load probability for a specific amount of generation. After only adding the first power plant for example, the loss of load probability is given by $F_1(80)$ because that was the size of the first station added and is in this case 1. This means that only with an 80 MW station, a system like the Estonian one would always face loss of load, which is a logical result.

The calculation of the LOLP with this method for multiple power plants can quickly become very complicated though, due to various power plants not having the same size and as such new brackets will constantly need to be calculated. To avoid those unnecessary complications without any loss of precision, it was assumed the 16 power plants would be modeled by blocks of 160 and 80 MW plants instead of their real sizes. The final result that will come out of this calculation will be largely unaffected by this approximation, as the size of the total system and its FOR will be unaffected. However if the conditions of the problem weren't so favorable, it would be suitable to develop an algorithm in order to calculate the various probabilities corresponding to a power system with uneven power plants.

Another issue with the calculation is the amount of brackets used to separate load levels. Again, as a matter of convenience, brackets were split into intervals of 80 MW in order to facilitate the computations. However, the effect of having less brackets will be examined as well by splitting the load levels into brackets of 160 MW and comparing the results. As will be seen, the number of brackets is somewhat significant and will account for higher precision. However, the brackets being equal to the smaller power plant is an approximation that will generate adequate precision, since splitting the load into more brackets will not alter the probability distribution significantly beyond the initial $F_0(x)$ input. As the smaller power plant is considered to be 80 MW, this is the size chosen for the brackets, while their sensitivity is tested by changing the bracket size to 160 MW.

With these approximations in mind, the convolution formula is used to calculate the loss of load probability when all 16 units are involved and the results are shown on the next table:

Generation size	Culm. Probability	Generation size	Culm. Probability
0	1	1600	0.13117
80	1	1680	0.08585
160	1	1760	0.05260
240	1	1840	0.03083
320	1	1920	0.01690
400	1	2000	0.00881
480	1	2080	0.00431
560	0.99896	2160	0.00199
640	0.99155	**2240**	**0.00087**
720	0.97793	2320	0.00035
800	0.94726	2400	0.00013
880	0.90285	2480	5.019E-05
960	0.83544	2560	1.715E-05
1040	0.75274	2720	1.641E-06
1120	0.65691	2880	1.192E-07
1200	0.55416	3040	6.360E-09
1280	0.45170	3200	2.367E-10
1360	0.35483	3360	5.623E-12
1440	0.26637	3520	7.078E-14
1520	0.19247	3680	2.697E-16

Table 2.3: Probability Distribution Table for all 16 units in Estonia

The highlighted purple value is the one corresponding to the total system generation. This is the LOLP of the system without the wind power, i.e. there is a 0.087% probability of loss of load in the Estonian system since its total size is 2240 MW.

The question that arises is how wind power should be included in this calculation. For a conventional power plant, it would simply be a matter of iterating once more the convolution formula and finding the LOLP for the new generation total. However, the stochastic nature of wind makes this approach difficult to implement. Wind power doesn't have one level of production, but several, depending on wind speeds typically ranging from 0 to 25 m/s. One approach could be to use the capacity factor of wind and determine the 'average' production of wind power and then treat wind as a normal power plant. This approach lacks accuracy as it does not capture the timing of wind power, i.e. if it affecting peak loads or not. This is crucial, because the probability of losing load only becomes significant near the peaks, especially for a system like the Estonian one with such a low LOLP.

A better approach, since the data is available, is to incorporate wind into the equivalent load duration curve. This is done by sorting and implementing the same process as previously starting with the net load duration curve instead of the simple load duration curve. As can be seen the difference is minimal, due to the fact that the wind capacity is quite limited at only 133 MW. To see what effect more wind capacity would have on the system, a scenario where wind production is multiplied 6 times for each time point, i.e. assuming a 800 MW wind capacity. Of course this isn't exactly accurate, since as said in the forecast error chapter an expansion of wind would definitely generate a different, smoother and less spiky time series. However, it is sufficient for the purposes of examining the effect of increased wind capacity on the power system.

To compare the effect of wind to the LOLP, the histogram of the net load values is calculated for both wind time series and then the convolution formula is used again with the initial equivalent (net) load distribution as input. The final results for all three scenarios, as well as the case with 160 MW brackets are shown on table 2.4 below:

80 MW brackets	LOLP	160 MW brackets	LOLP
Load Duration Curve	**0. 087%**	Load Duration Curve	**0.254%**
Net Load Duration Curve	**0.073%**	Net Load Duration Curve	**0.215%**
Net Load Duration Curve-800 MW Wind	**0.038%**	Net Load Duration Curve-800 MW Wind	**0.120%**

Table 2.4: LOLP results for different scenarios and load distributions

The entire final distribution with all power plants included for the three different distributions with 80 MW brackets is shown below:

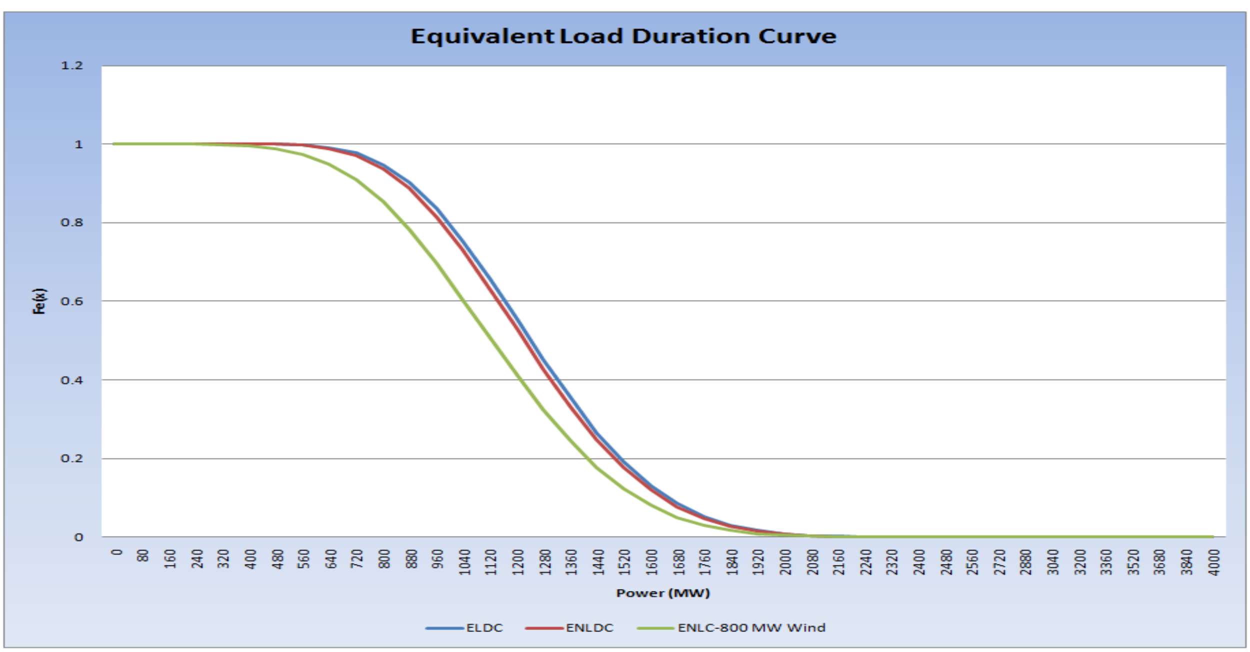

Figure 2.5: Equivalent load duration curve for load, net load and net load with 800 MW wind distributions

As it can be seen, the difference in bracket choice can provide a result that is 3 times as small. This is because the initial $F_0(x)$ LDC changes significantly as the number of brackets becomes larger. To achieve greater accuracy, it is important to increase the number of brackets. However, this cannot be done indefinitely as it can complicate the calculations significantly. In this particular system, the results are small enough anyway to make little absolute difference. There are about 14 hours of lost load per year of difference between the two results, which is a significant relative decrease but results in an anyway small number of hours per year lost (8 hours versus 22 hours).The difference is attributed to the difference in LOLP, which is almost tripled in the 160 MW bracket case, but still significantly low (0.0025). In any case, the results from the scenario with 80 MW brackets are the ones that will be considered most accurate. To get the yearly load losses as those mentioned previously, the LOLP probability is multiplied with the amount of hours in a year. The next table shows the amount of megawatt hours lost per year.

80 MW brackets	MWh lost	160 MW brackets	MWh lost
Load Duration Curve	**7.63**	Load Duration Curve	**22.27**
Net Load Duration Curve	**6.38**	Net Load Duration Curve	**18.81**
Net Load Duration Curve-800 MW Wind	**3.34**	Net Load Duration Curve-800 MW Wind	**10.52**

Table 2.5: MWh lost according to LOLP calculations

From these results it can be seen that the existing wind capacity and its potential expansion will diminish the LOLP and hours lost greatly in a relative sense (more than 100% decrease compared to status quo) but are not so important in the absolute sense. An 800 MW wind capacity would only save 3-12 MWh which is a relatively small amount of power.

Having calculated the LOLP for each scenario, it is now possible to complete the capacity credit calculations according to the methods described in the theory subchapter. For the first three methods (equivalent firm capacity, equivalent conventional power plant, load carrying capacity) formulas [4]-[6] will be used to calculate the capacity credit.

A. Equivalent firm capacity

This will be calculated using formula [4]:

$$C_{EFC} = F_{E_{k-1}}^{-1}(LOLP_g) - \sum_{1}^{k-1} G_k \quad [4]$$

The first term in the right hand part of the formula is the point in the ELDC that corresponds to a LOLP equal to 0.073%, which is the LOLP for the case where the net load duration curve is taken into account. The total generation has to be subtracted from that value in order to assess how much a fictitious 100% reliable unit would contribute.

To find this value, the value for which the LOLP of the original curve is the same as the net load duration curve, some interpolation is required. Plotting a small part of the duration curves close to the capacity of the Estonian system, it can be seen that it follows accurately a function of the type:

$$F_E(x) = \frac{a}{x} + b \ [8]$$

This can be shown when the LDC is plotted for small intervals, like shown on figure 2.6 below:

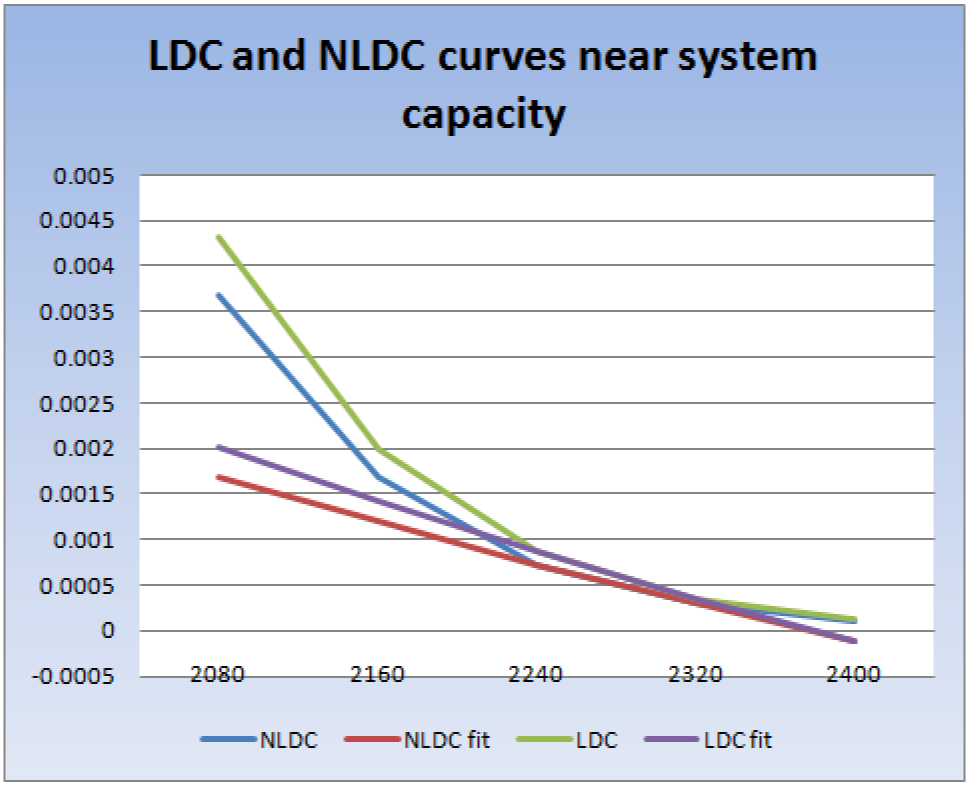

Figure 2.6: LDC and NLDC short interval curves

The correlation between the interpolated function [8] and the real functions were calculated and found to always be above 0.9 for each scenario, making sure that the results were accurate for the interval studied.

With that in mind, it is easy to calculate the results for the firm capacity after finding the coefficients used in formula [9]. The results are shown on table 2.6.

Wind Potential	Equivalent Firm Capacity	% of wind capacity to conventional	EFC/Total Capacity
133 MW	**21.74 MW**	**16.35%**	**0.92%**
800 MW	**76.06 MW**	**9.51%**	**2.52%**

Table 2.6: Equivalent Firm Capacity

As it can be seen, the 133 MW of wind correspond to a 100% reliable fictitious plant that has a capacity of 21.74 MW. The final column shows the ratio of the first two columns. This shows that an increased penetration of wind will reduce the capacity credit attributed to it. This is logical in a system like the Estonian where there is already abundant capacity and additional units will benefit capacity adequacy less and less.

B. Equivalent conventional power plant

In accordance with Elering's data for its existing power plants, it was chosen that the FOR of the fictitious conventional power plant would be set to 8% which is close to what the newest Estonian power plants list as their FOR. The next step is solving equation [5]:

$$F_{E_{k-1}}^{-1}\left(\frac{LOLP_g - (1 - p_{ECC}) * F_{E_{k-1}}^{-1}\left(\sum_1^k G_k\right)}{p_{ECC}}\right) = F_{E_{k-1}}^{-1}\left(\frac{0.000728 - 0.08 * 0.000871}{0.92}\right)$$

$$C_{ECC} == F_{E_{k-1}}^{-1}(0.000715) - \sum_1^k G_k = 23.65\ MW$$

And the equivalent calculation is made for the 800 MW wind case and the results are presented below:

Wind Potential	Equivalent Conventional Power Plant Capacity	% of wind capacity to conventional	ECC/Total Capacity
133 MW	23.65 MW	17.78%	1.00%
800 MW	82.92 MW	10.37%	2.75%

Table 2.7: Equivalent Conventional Power Plant Capacity

The results are very similar to the previous case. A MW of wind in the current situation corresponds to the additional capacity that 0.18 MW of a 92% reliable thermal power plant would offer.

C. Load Carrying Capacity

The load carrying capacity is provided by formula [6]:

$$C_{ELCC} = \sum_1^k G_k - F_{E_k}^{-1}\left(LOLP_{g-1}\right) = 2240\ MW - F_{E_k}^{-1}(0.000871)$$

And the results are shown on the table below:

Wind Potential	Load Carrying Capacity	% of wind capacity to LCC	LCC/Total Capacity
133 MW	25.24 MW	18.98%	1.06%
800 MW	151.96 MW	19.00%	5.02%

Table 2.8 Load Carrying Capacity

It can be noted that there is an upward difference of the LCC compared to the previous methods. However, their trend is similar. The higher result can be explained by understanding that with this method something different is studied. Instead of looking at the supply equivalent of the wind, this method focuses on the demand effect of the wind. The essential result though is that it confirms that wind power would somewhat contribute to adequacy even in higher penetration levels, despite the fact that this contribution would be small.

D. Guaranteed or Secure Capacity

This formula is less accurate than the analytical way of calculating the capacity outage table since it only results in 17 states compared to the almost 1 million states the capacity outage table could have but the results are more clean, don't document thousand states which are only set apart from 1-2 MW and they can be produced more fast and efficiently without missing too much on accuracy. This is the reason this approach is the most commonly used one in the literature [3], [6]. The results are portrayed in the table below:

Load Levels (MW)	Level of supply reliability
0	2.581E-15
80	2.424E-13
170	1.124E-11
320	3.400E-10
480	7.416E-09
640	1.221E-07
800	1.554E-06
960	1.550E-05
1120	0.00012
1280	0.00077
1480	0.00394
1510	0.01629
1670	0.05505
1830	0.15238
2000	0.34330
2190	0.61938
2240	0.88019

Table 2.9: LOLP and corresponding load levels for the Estonian system

It needs to be reminded that the probability calculated in the right hand column is not the LOLP but a parameter of the system independent of its actual characteristics that describes only the probability that a given level of load will be served at any time.

The highlighted result is the one that corresponds to peak demand, which is 1510 MW in the Estonian system. As such the table shows that at peak load there's a 1.63% probability of shedding some load. There are measurable chances that some load might be shed in other, non peak-load states too, but those quickly deteriorate and become negligible only a few MW below the peak load. A chart of the cumulative probability of 'supply reliability' can be seen in the figure below:

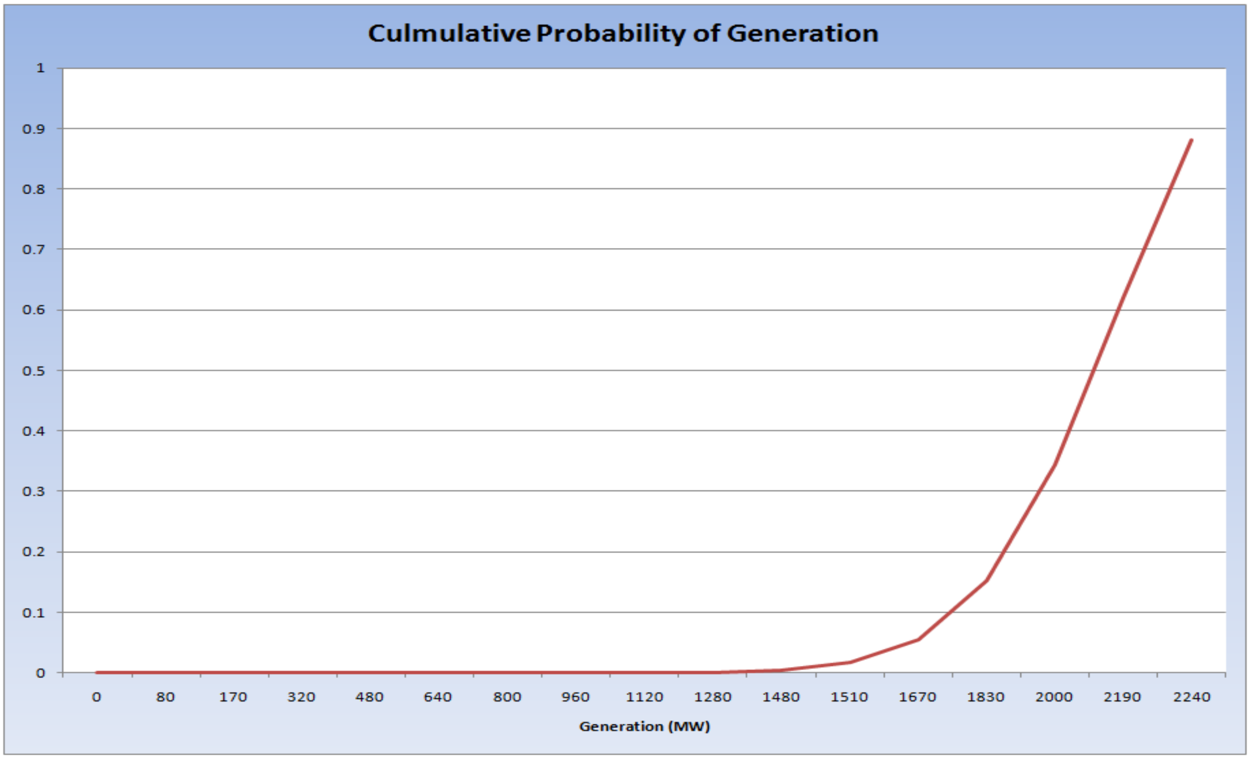

Figure 2.7: Cumulative probability of generation with the guaranteed capacity method

Typically, for a thermal unit, the guaranteed capacity table would be calculated again with that extra unit and formula [7] would be used to determine the guaranteed capacity difference. However, since wind cannot be added like a conventional power plant would, a different approach is tried.

The first step is to calculate the amount of MW shed due to insufficient capacity in the current system. This is done by multiplying the "level of supply reliability" for each load bracket with the amount of hours that the load acquires these values. Then the same is done for the net load duration curve. The difference is the energy expected to be lost without and with the wind farms. Formula [10] below shows the mathematical expression of this calculation:

$$EENS_{gc} = R_k(1510) * \sum_{i=1480}^{1510} f_i + R_k(1480) * \sum_{i=1290}^{1480} f_i + \cdots - R_k(1480) * \sum_{i=1290}^{1480} j_i - \cdots [9]$$

where $\sum_{i=1480}^{1510} f_i$ is for example the sum of observations of the load duration curve in the 1480-1510 MW bracket and $\sum_{i=1290}^{1480} j_i$ is the sum of observations of the net load duration curve in that bracket. The results can be seen in table 2.10 below:

\

	Amount of total MWh lost
Load Duration Curve	**3.07**
Net Load Duration Curve	**2.60**
Difference	**0.47**

Table 2.10: Energy lost with and without wind energy in Estonia using the guaranteed capacity method

As expected this value is quite. Over the last year there were only six occasions where the load has climbed above 1480 MW, which corresponds to a 0.07% chance for the exceeding the peak load of the net load duration curve to occur. There have been only 30 occasions of the load exceeding that value in the past 5 years. As seen again, the contribution of wind to supply security is not that important, due to the abundant capacity in the Estonian system. However, this should not be mistaken with seeing the wind as unable to provide any capacity benefit, albeit small.

For the purposes of testing the sensitivity of this method, the previous calculations are remade, only this time adding a 300 MW natural gas plant with 8% FOR and the case of 800 MW wind which was used in previous scenarios as well. The new values for the energy lost are shown in table 2.11 below, where it can be seen that wind definitely would not offer as much of a capacity relief as a normal unit generator, but would still contribute something to system security.

Case study	Hours Lost per year
Current status	3.07
With 133 MW of wind	2.60
With 800 MW of wind	0.76
With 300 MW nat. gas	0.01

Table 2.11: Hours of energy lost for different scenarios, guaranteed capacity method

The conclusion is wind does not change dramatically the amount of energy lost even in higher penetration levels. However, a new big thermal plant would pretty much eliminate any lost load situation that can currently happen. All results should be taken under consideration cautiously though, as it is important to understand that this method doesn’t reflect any positive or negative correlations of the wind and the load and generally ignores the properties of the system.

Finally, the cumulative probability of both conventional power plant cases is shown below to depict how the addition of a new thermal unit changes the probability table and the level of guaranteed capacity.

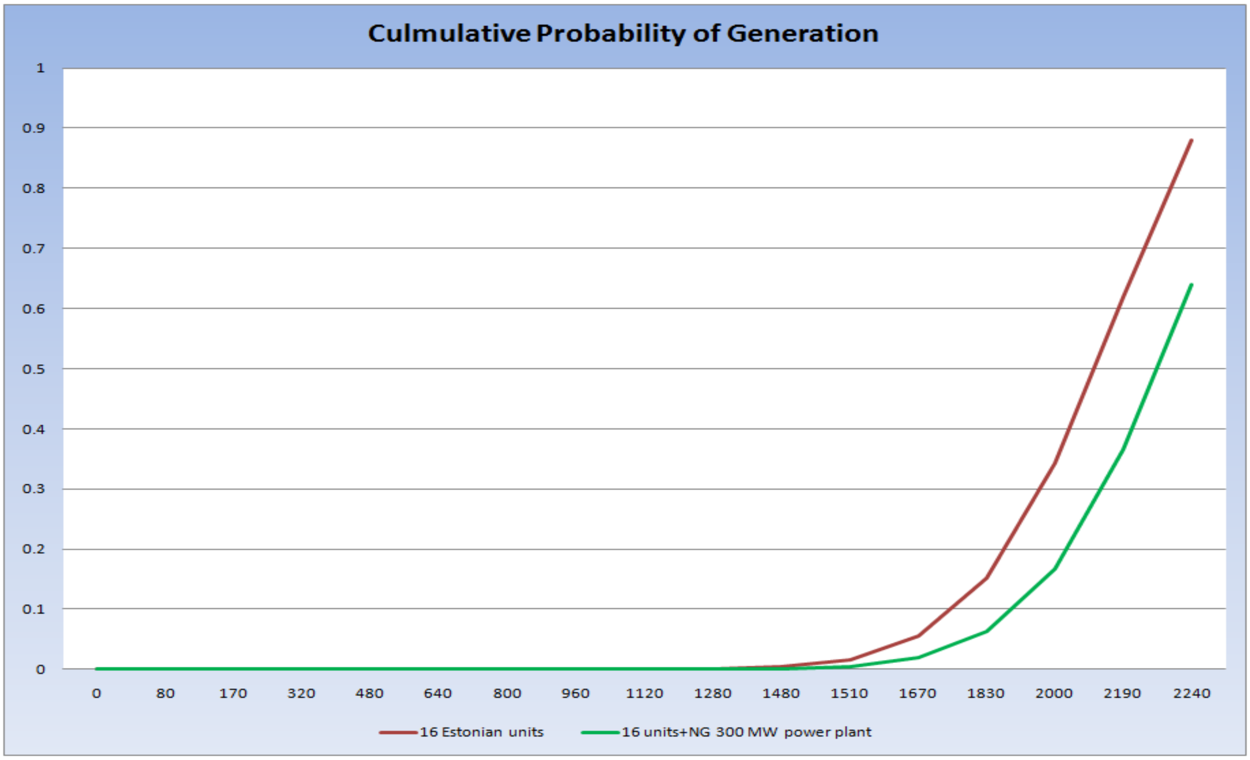

Figure 2.8: Cumulative probability for default scenario and 300 MW nat. gas power plant scenario

It can be seen that the steep decrease in hours of load lost is due to a decrease of the probability of the supply not exceeding certain levels throughout all the possible generation values.

2.4 The effect of Interconnections

In all those calculations made above for all various methods, Estonia was implied to be an 'island' case, i.e. without any interconnections to the outside world. However this is untrue and Estonia does possess the possibility to use energy from the Baltic countries, Russia and Finland to balance its demand and supply of electricity. Due to the LOLP and capacity credit of wind being already exceedingly small the interconnections will not alter the results significantly, it is useful however to at least consider a scenario with interconnections present and recalculate the previous indexes. In this study, only the 350 MW of Estlink connecting Estonia to Finland will be considered, as the Estonian TSO considers the rest of the interconnections unreliable and does not wish to take them into account when conducting its energy planning.

A question is how interconnections should be modeled. In this case, the choice will be to handle them as a conventional power plant, with 0.5 and 0.7 FOR. This reflects not the technical failures of the interconnecting lines which are negligible but the fact that interconnections can at times be unavailable due to imbalances in the neighboring regions. The case where interconnections are not available has already been studied in the previous example and as such the cases of interest here are ones with relatively high potential for interconnection use, hence the chosen FOR.

The recalculations are made and the results are shown on table 2.12 below, for all 3 methods involving the use of LOLP, producing the new capacity credit according to each method.

Scenario	EFC (MW)	ECC (MW)	LCC (MW)
No I/C	21.74	23.65	25.24
0.5 FOR I/C	10.40	11.31	12.14
0.3 FOR I/C	10.25	11.15	11.98
No I/C-800 MW wind	76.06	82.92	151.96
0.5 FOR I/C-800 MW wind	35.89	39.05	72.58
0.3 FOR I/C-800 MW wind	35.35	38.47	71.81

Table 2.12: Capacity credit for each method with the addition of interconnections

It is obvious that the interconnection, similar to the effect a big thermal power plant would have is significantly decreasing the wind power's capacity credit. However, the FOR of the interconnection doesn't seem to matter as much. A 0.2 difference between the two scenarios produces only 1 MW of difference for the wind power capacity credit. The essential result from this calculation is that accounting for interconnections a capacity as big as 800 MW of wind will only account for approximately 35-40 more MW of installed capacity when it comes to system adequacy. As such and along with the previous results it should be concluded that any further possible expansion of wind in Estonia will not contribute significantly to system reliability and adequacy.

2.5 The effect of time series choice and changes in generation capacity

Another issue is how the selected year influences the LOLP and capacity credit calculations. In the previous calculations only the year 2009 was studied to reach conclusions about wind power's contribution to capacity adequacy. However, wind energy output as well as load consumption tends to fluctuate throughout several years and the results must be tested with another year to compare the results and make sure of their validity.

It is however required that wind capacity remains at the same level, something that hasn't happened in Estonia in the past 5 years, as wind power has been steadily increasing. As such, the wind time series for 2007 and 2008 were scaled upwards so that they correspond to the same capacity as for 2009. This is problematic for reasons explained in chapter 3 about forecasting, but considering the low values of wind power production and the fact it's concentrated in the same region, it is assumed no significant variations from what the real time series would look like have occurred.

Another issue that requires some further study is what would be the capacity credit if thermal capacity was significantly lower. Considering that there are plans to reduce thermal capacity in Estonia, this is a scenario worth studying. As such, the capacity credit is examined in the case that thermal capacity was down to 1600 MW, only 100 MW above the peak load observed values.

The results of the different scenarios are incorporated in the following table:

Scenario	EFC (MW)	ECC (MW)	LCC (MW)
2009	21.74	23.65	25.24
2008	28.65	31.18	35.03
2007	32.37	35.23	41.08
1600 MW thermal capacity	44.77	45.64	57.31
1600 MW thermal capacity % increase	206%	193%	227%

Table 2.13: Capacity credit of wind for different scenarios

As it can be seen, the difference between the different years is relatively significant, as the capacity credit can acquire a value one and a half times higher than previously. However it should be noted that there are not comparable and precise time series with the same amount of wind capacity to compare the different years and as such these results should be approached with caution.

The most interesting result is the increase of wind's capacity credit as thermal capacity goes down. If conventional capacity was down to 1600 MW, the capacity credit of wind would double. This highlights that the reason wind's capacity credit is so small is that there is abundant capacity in the system and new capacity cannot contribute too much. Furthermore, the load carrying capability is now 57.31, which corresponds to 43% of installed capacity. This is a significant increase and higher than results from other studies [4].

3. Forecast Errors

3.1 Forecast Errors and wind power variability

What is very often seen as a major disadvantage with wind power production is the intermittency of wind and the sudden changes that might occur in wind power output forcing the power system out of its desired state of supply and demand equilibrium. The core of the problem though lies in the lack of reliable predictability of wind power or alternatively wind speed. If wind speed was accurately forecasted several hours or days ahead it would be possible to precisely estimate the amount of wind power produced at each specific moment and all that it would take to integrate wind power into the system would be accurately matching the ramp up and down rates for thermal units, which while not a negligible task is fairly more straight forward (even if it still carries significant costs [7]).

However, accurately predicting the weather and wind speeds has been a major challenge as it is a very complicated problem with a lot of variables and unknown factors. Even the most modern and accurate models can lead to wrong predictions [8], [9], [10]. If those time errors persist to nearer time horizons they can be cause of augmented costs for a TSO looking to balance demand and supply. As such, several approaches have been used in order to create an accurate and descriptive model of wind speed/power prediction. The objective has been to minimize the forecast error, taking the time horizon that is of most interest under consideration. Different approaches may yield better results if used for longer time horizons (>5 hours or >24 hours) or shorter time horizons (<3 hours).

A typical wind power forecasting system will use the meteorological service's weather model to predict wind speeds and their direction. These models are very reliable and are running all day long. There are a number of established forecast models used by different researchers, public authorities and TSO's which have varying degrees of success [8], [10].

Typically, a model's success will be measured against the persistence model (or the actual production if data about it is available). The persistence model simply consists of assuming that the future values of wind power output will be equal to the previous ones, or:

$$P_i = P_{i-1}$$

While this seems a very simplistic approach, wind power output is not particularly volatile in small time horizons and as such the persistence model is quite accurate in time horizons less than 3 hours long. Below, a comparison of the persistence model and WPPT (Wind Power Prediction Tool) model is shown [8].

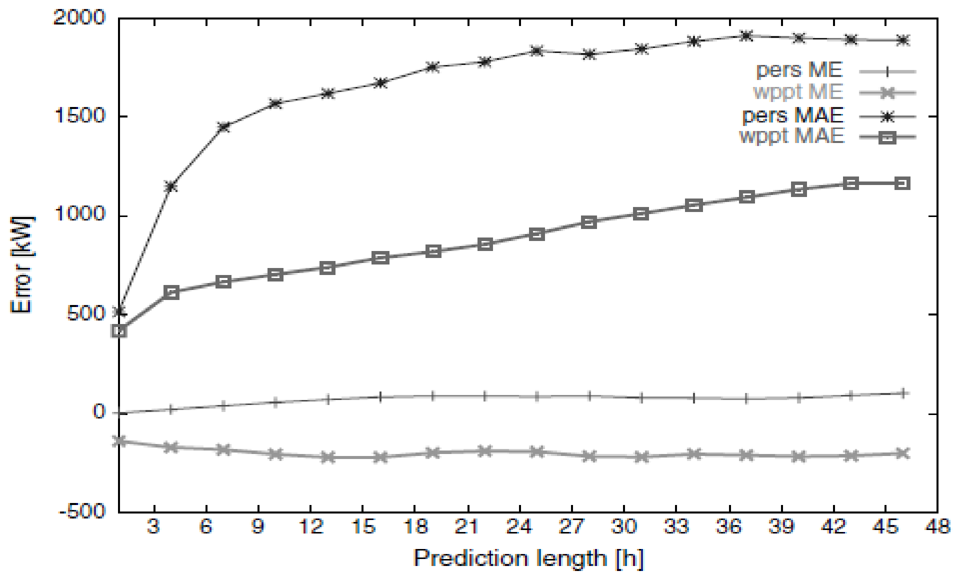

Figure 3.1 Comparison of persistence and WPPT model for forecasting wind power [8]

As it can be seen, the persistence model is fairly accurate up to 3 hours after an observation, making it a useful benchmark for a model's success. The success of the persistence model dispels a myth that wind power is prone to violent and sudden changes, which can be further showcased by the graph below showing the normalized values of hourly and per minute wind output change for a month (Jan. 2008) in Estonia. It can be seen that on the per minute basis, wind power is actually never changing by more than 0.1 of its rated capacity, and probably even lower for areas like DK-West with higher wind penetration.

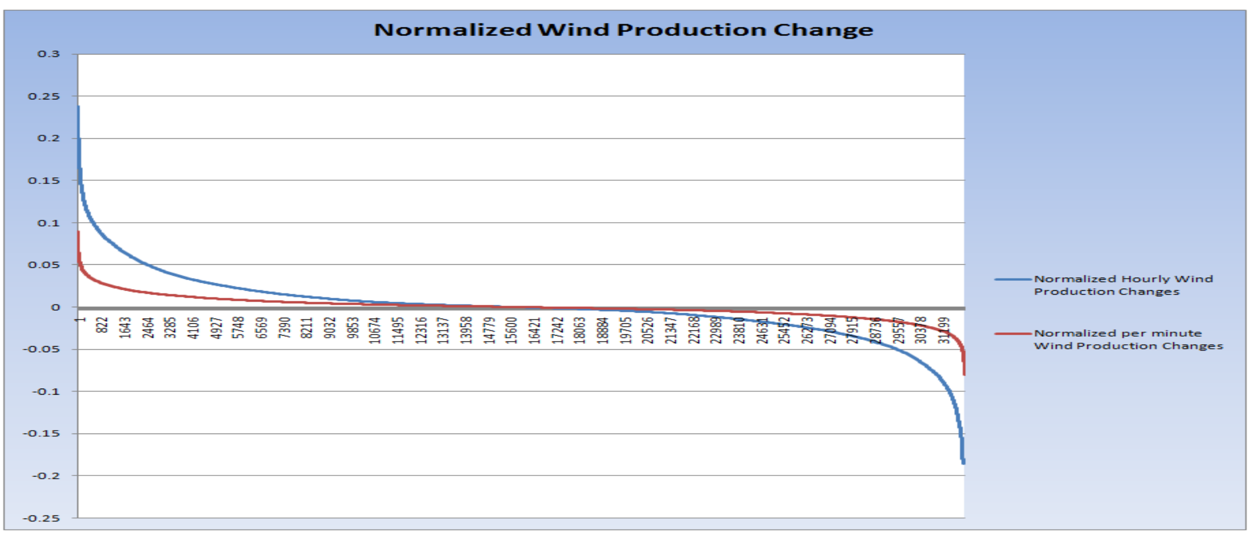

Figure 3.2: Normalized (with capacity) hourly and per minute wind power changes

Even in the hourly case, wind changes are never exceeding 0.25 of the wind capacity. The same process has been applied on additional months with similar results, even if there were some occasional greater spikes in hourly wind power changes.

Further proof of the fact is provided by the following comparison of hourly wind power changes throughout a year (2007) in Estonia and the two Danish power regions (as well as their aggregated sum, see figure 2.1).

It can be seen that the Estonian system suffers from greater wind output volatility compared to the Danish cases. This is reasonable due to an effect called **'spatial smoothing'**. The principle behind it is that by expanding wind power in greater areas such as Denmark, violent and sudden changes of power output in one area are counterbalanced by similar developments in other areas or simply become statistically unimportant since as seen previously wind speeds tend to be persistent in nature and follow a very slow changing pattern. Since wind output of different wind farms in dispersed locations are usually not correlated (or even negatively correlated) this means that big changes in output in one power farm will not be important from a system perspective since there is a large probability that other wind farms will not follow the same trend.

This is evident from the fact that Western Denmark, the area with the highest penetration of wind power into its energy system presents lower values of volatility than the other two regions. In comparison, Estonia's current small capacity (133 MW) is heavily influenced by perturbations in one or two wind farms.

Another important issue with wind variability is that it is more obvious and volatile near the middle of a wind farm's (or area's) rated output. This is happening because the wind output is dependent on the cube of the wind speed and as such variations in the middle of the power curve result in higher variability (this doesn't happen at the higher end of the curve because there is a speed beyond which wind turbines stop increasing their output and a cut off speed where they stop operating). For the Estonian case this became evident with the following method.
The values of wind production found in the 2007 time series were split into 10 normalized intervals, each one signifying a level in production (i.e. from 0 to 0.1 rated power, from 0.1 to 0.2 etc.) and then the average change within the next hour for each interval was computed. The results can be seen below:

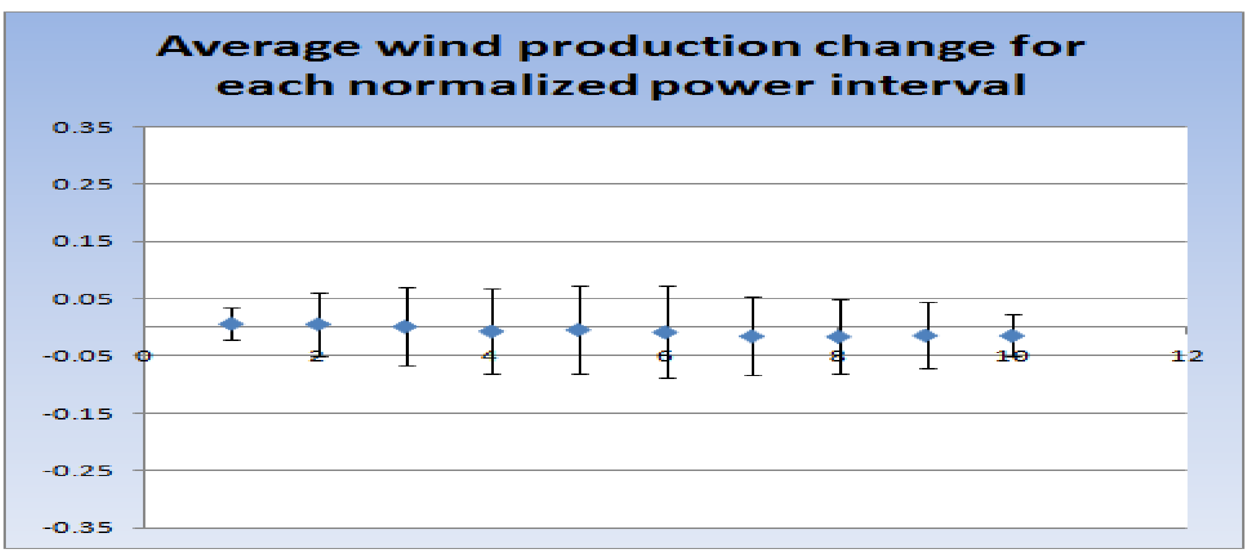

Figure 3.3: Average normalized wind power change for intervals of rated output

It can be seen that it is intervals 4-7 (corresponding to 0.4-0.7 normalized output) where the most volatile changes occur. This is significant because wind power does not follow a normal distribution but a Weibull/exponential one which is heavily skewed towards smaller values (the capacity factor is 26% while for a normal distribution it should be 50%). As such the cases with the lowest volatility are the ones with the highest chances of occurring, so all in all the effect of wind unpredictability is somewhat mitigated by having lower uncertainty for the most common states.

3.2 Danish and German forecast systems and errors

To get an idea of the different forecast systems and their respective accuracy, available forecast data from two well established models operating in Denmark and Germany were compared to each other. The Danish system data was found by Energinet [5] while the German data is publically provided by enBW [11], a TSO operating in the Baden-Wurttemberg area of Germany. These are also compared with other results provided in the international literature as well as some data from the Estonian TSO, Elering [12].

The first question is the determination of the relevant metric to measure what the forecast error is. There are quite a few suggestions and approaches in the literature [10], [9] and the most relevant metrics are the mean absolute error (MAE) and the root-mean square error (RMSE). The formulas for calculating the two errors are:

$$MAE = \frac{1}{n}\sum_{i=1}^{n} f_i - x_i$$

$$RMSE = \sqrt{\frac{\sum_{i=1}^{n}(f_i - x_i)^2}{n}}$$

Where n is the sample size, f is the forecasted value and x is the actual produced value of wind power.
Data in the form of time series was retrieved from August 2009 until March 2010 for the Baden-Wurttemberg area and from September 2009 until January 2010 for Western Denmark. Also, some data from Elering's website were used from January until March 2010 but the short time span of this data and doubts about the accuracy of the maximum capacity means they should mostly be ignored (and Elering acknowledges the forecasting system in Estonia is not adequately accurate). All of the time series were forecasts conducted 16-32 hours ahead of time (for example a forecast was made at 1 am on day one that produced forecasted values for the time range between 7 pm on day 1 and 7 am on day two). Calculations using the time series produced the following results:

	Baden-Wurttemberg	Jutland	Estonia
Capacity (MW)	373	2115	113
MAE (or average error) (MW)	27.22	131.58	10.76
NMAE (Normalized Avg. Error)	7.3%	6.2%	9.5%
Standard Deviation (MW)	37.72	118.82	13.87
Normalized Std. Deviation	10.1%	5.0%	12.0%
Correlation between forecast and production	84.0%	94.0%	87.7%
RMSE (MW)	39.41	177.30	15.10
Normalized RMSE	10.57%	8.38%	13.36%

Table 3.1: Statistical quantities of forecast errors in 3 regions

From the results of this inquiry it is apparent that Jutland has the best forecasting model as the average difference between the forecast and the actual production is merely 6.2% of the installed capacity. This accuracy is very helpful in determining a range of values that the wind output will lie in during the next 24 hours in order to get more accurate solutions to the optimal dispatch problem.

The reason for the difference in error values in the three different regions come down to a variety of factors. First of all, the accuracy and prediction capabilities of the models used could be different. Secondly, as previously mentioned a 'smoothing' effect could be behind the observed differences. This is examined in further detail in the next chapter. Finally, the difference in the time span of the observations could play a role in the noted differences. Below, a comparison of the forecasted and actual values for the Jutland case can be seen:

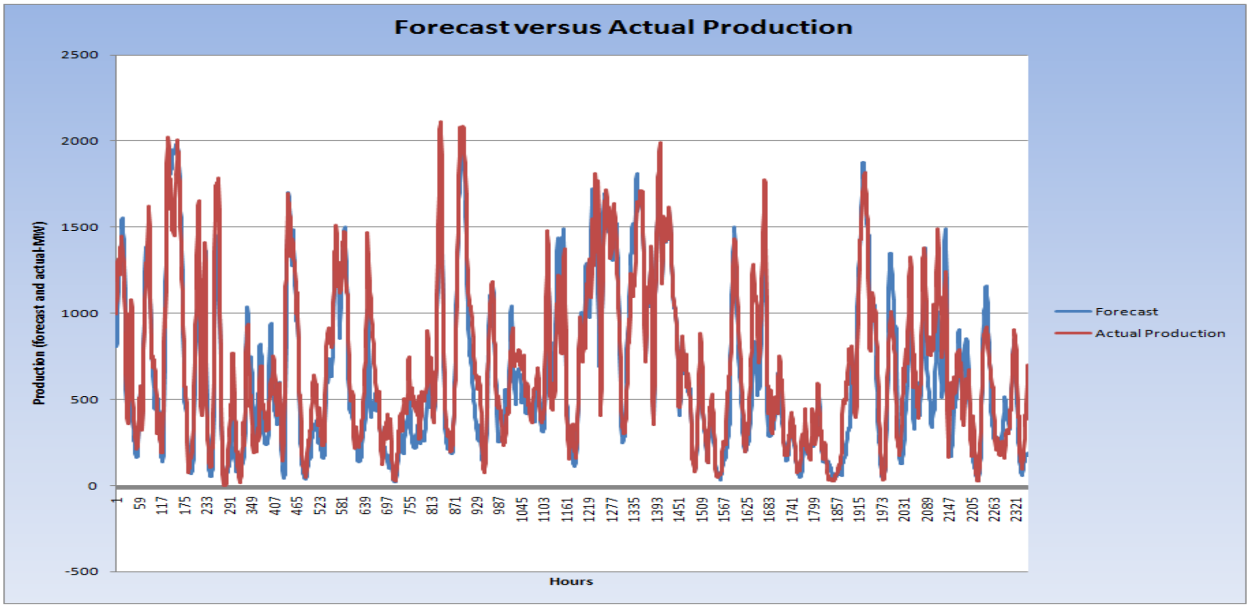

Figure 3.4: Forecast versus Actual production in Jutland,DK [5]

Another consideration is again the values of wind power for which the forecast error acquires its most significant values. From the data from Baden-Wurttemberg this time, the following figure shows that once again most of the prediction problems lie in the higher end of wind output values. The relative rarity of those values explains why greater statistical values in those is influencing average forecast error less than the smaller errors observed around the capacity factor of the machines.

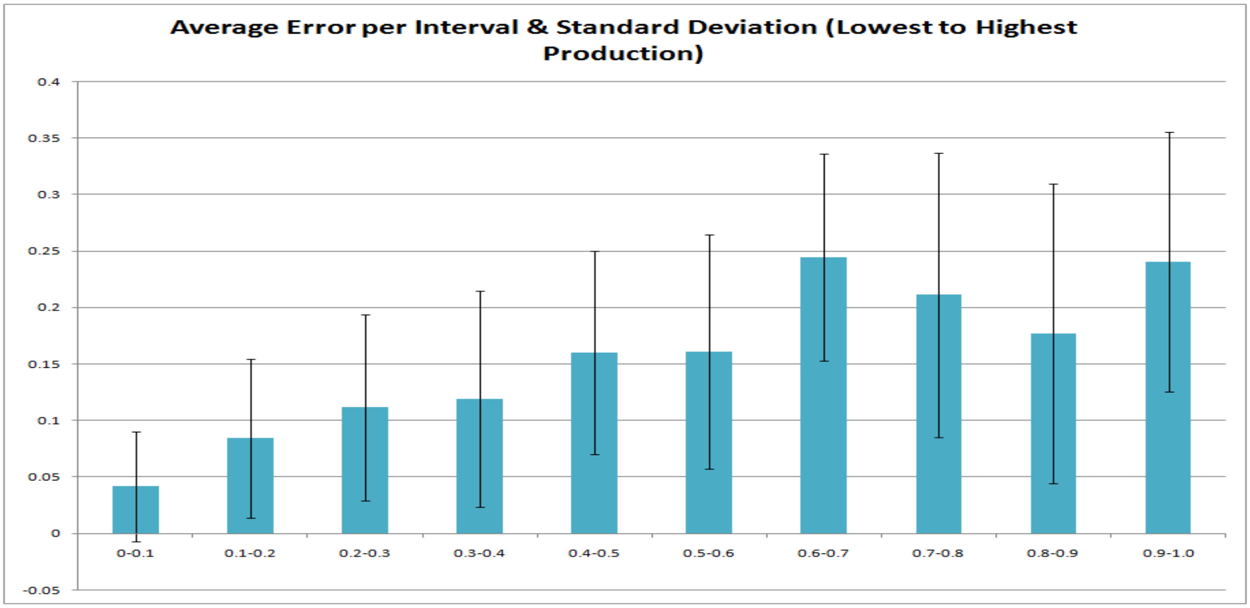

Figure 3.5: Average error and standard deviation for each interval of wind power output normalized with the wind capacity, Baden-Wurttemberg

3.3 Forecast error 'Smoothing'

There has been somewhat limited research on the effect a large penetration of wide spread in a large area has on the predictability of wind but some recent reports show a definite improvement of forecast accuracy when this happens. This effect is called 'spatial smoothing' and works particularly for a small time horizon. It appears that for relatively short time horizons (between 0 and 36 hours) the output of wind turbines spread throughout a large region are uncorrelated and this effect increases with distance. The combination of high penetration and spatial variation of wind power is especially beneficial for forecast accuracy as individual turbine or farms steep differentials are counterbalanced by opposite trends in other regions (i.e. the errors are cancelling out each other) or simply the effect of one wind farm on the whole wind production becomes negligible.

This needs to be taken under account when any estimate for future expansions of wind resources are considered as it is almost certain that predictability of the resource will be increased due to expansion. This is best showcased in a paper by Focken et al [13] where the results of aggregating power outputs of several German wind farms reduces the forecast error by a significant amount and seems to have far more impact on it than time horizon.

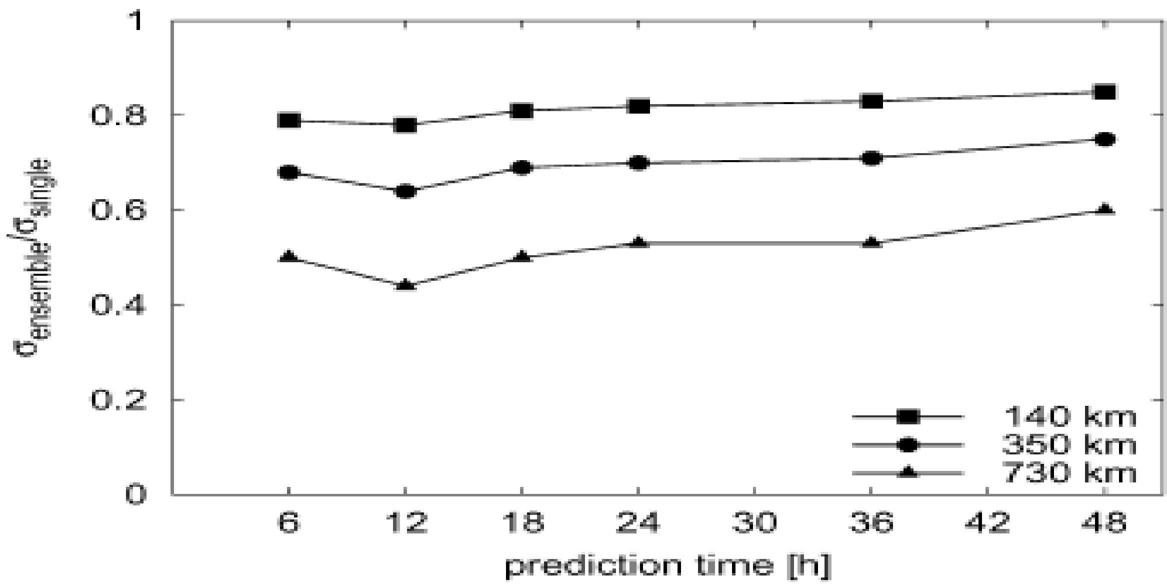

Figure 3.6: Ratio between ensemble and single time series for various wind farms and different time horizons

From figure 3.7 it can be seen that when the outputs of different wind farms are aggregated over a wider region, the variability of the ensemble (the aggregated output) can become even half of the single wind farm one (for example for an area of 730 km). In the TradeWind report on forecast errors [9] the same results are verified and compared to another report by Boone [14] where the following results are published:

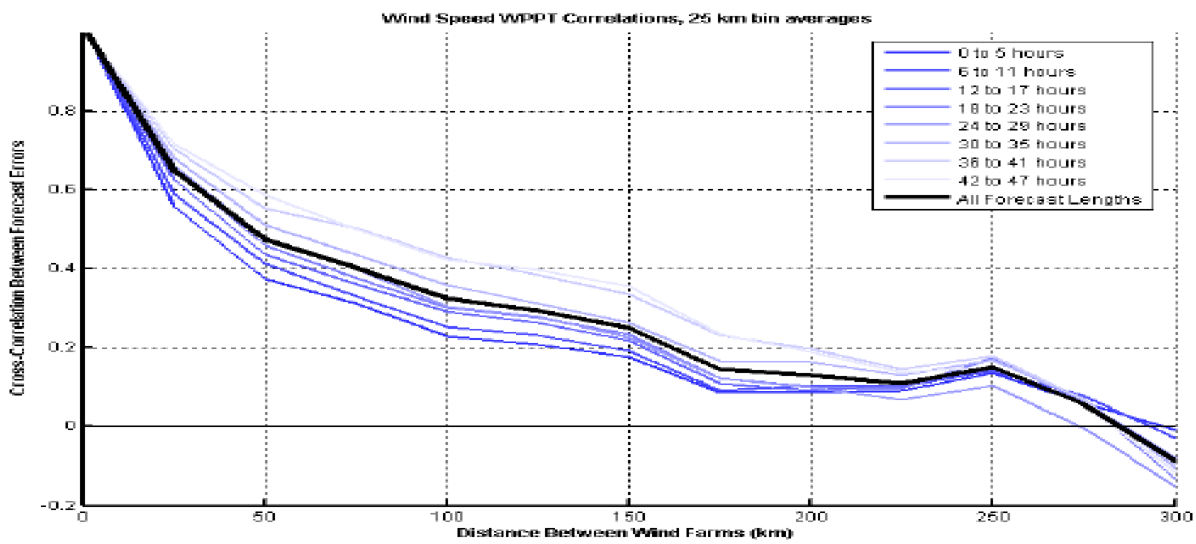

Figure 3.7: Correlation between wind farm forecast errors dependent on distance

The results are similar to those in figure 3.7 and should be taken under consideration if upscaling of the existing wind capacity in Estonia is to be attempted. It is apparent that the forecast errors are not correlated and as such it can be assumed that the forecast becomes more accurate with the expansion of the wind network.

4. Reserve Planning and wind variability

4.1 Reserve classification and relation to wind variability

Reserves are an important topic for all TSO's since the balance of demand and supply is not always a given. Estonia's large overcapacity is definitely an important asset in assuring the system always has adequate reserves but there are a lot of units with slow start up times which may not be readily available to cover any excess demand or wind output decreases. Furthermore, it's not very economical to operate excess thermal units around the clock unless there's an indication that they will actually be required to fulfill demand at some point. So the questions raised are how many reserves (size of reserves) are required by the system at each time and what kind of reserves are those.

There is a variety of reserves, but most power systems follow the same guidelines and classify reserves in one of the following categories, according to the response time required by those reserves:

a) Primary (or regulation) reserves which are reserves that can be employed within a very short time frame after a surge in demand occurs. This kind of reserve is usually provided by regulating units operating at below maximum capacity. When supply and demand are imbalanced the change in system frequency activates those reserves according to their 'droop' settings which determine the proportion of the load that each power plant will carry. These units typically need to have a fast ramping rate to accommodate for any sudden load/supply changes.

b) Disturbance or contingency reserve is the second kind of reserve that is typically (but not necessarily) spinning, i.e. it relies on generators already operating. In any case it consists of fast units that are able to respond to a contingency within seconds/minutes. This kind of reserve's size is determined by the size of the largest generator in the grid, allowing for a relatively smooth response to any unit in the grid tripping (also known as the n-1 principle). In practice, TSO's often merge this kind of reserves with primary reserves. For example Energinet.dk makes no separation between the two kinds of reserves and assumes the probability of a contingency and large wind/load variation occurring simultaneously is insignificant (or could be solved through interconnection use in the rare chance it occurs).

c) The last kind of reserve, called slow reserves consists of slower starting units that can be available and synchronized within approximately 10 minutes or more. These units are called upon to contribute to serving the load and relieving the primary reserve units who can then go back to their pre-designed point of operation to ensure they are available for another frequency perturbation. This type of reserve can be broken down to different categories (sub-10 minute units, 30 minute units, 1 hour units etc.) but for the purpose of this study only planning of units on the hourly and 24-hour ahead basis will be of any concern.

The Estonian system's grid code already incorporates provisions for the separation of reserves into primary and contingency ones [1].

To determine reserve planning, two parameters are critical. The amount of time prior to activation the TSO will commit the reserves (there are intraday, 24 hour ahead and other markets where the TSO buys reserve capacity) and the ramping up/start up characteristics of the power plants used as reserves. Another issue is the correct dimensioning of the system reserves according to those two guidelines.

4.2 Reserve Dimensioning Principles

Typically among TSO's, the n-1 principle applies, i.e. reserves are high enough that they can withstand the tripping of the biggest power generator. However in systems with increased penetration of wind power and big loads subject to sudden changes another approach, taking under consideration the variability of loads and wind should be considered. The Estonian TSO has plans for installing a large quantity of wind power, so steep wind swings could require fast responding and possibly many reserves. Once the wind capacity reaches a level equivalent to the average load demand, wind changes become significant for reserve planning. But when upscaling of the installed wind capacity is considered, it should be remembered that there's a forecast error smoothing effect.

The most common way to determine the level of reserve required for the system is to find out the standard deviation of the net load (load minus wind power). Since load and wind forecast errors follow distributions close to normal (but not exactly normal), three standard deviations away from the mean should cover 99.7% of the possible outcomes while four standard deviations will cover 99.99%. A second approach is to instead use the existing time series of wind to determine which values of forecast error are higher than 99.7% of the observed values and use this as a reserve guideline. This method could be useful for determining how close to normally distributed the forecast errors are.

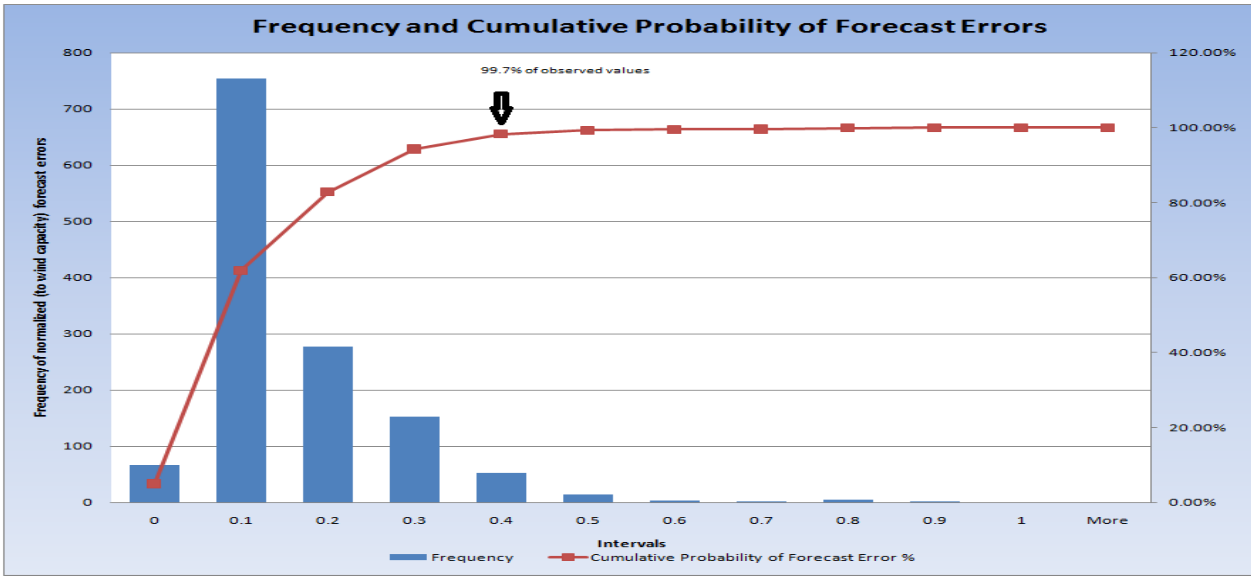

Figure 4.1: Frequency and cumulative distribution of forecast errors for Estonia 2009

A question that arises is whether it should be actual load and wind variability taken under account when computing the standard deviation (based on existing time series of these quantities) or the forecast error variability of load and wind power. Different approaches have been used in the literature.

The answer provided here is that this depends mostly on the type of reserves, what the objective is and whether an accurate forecast is available. For frequency reserves that need to operate almost in real time, basing the reserves on a forecast would require the development of per minute (or shorter) forecast that the system would able to process in this kind of time frame. In this case it is better to base the reserve requirements on the known statistical variability of wind and load per minute. The system is trying to 'follow' the load in this case, so it is reasonable to have reserves able to cope with the possible changes of the load according to historic time series of it.

In the hourly case, reserve planning becomes more complicated. The reason for this is that a unit commitment schedule produced by a program such as BALMOREL has already assigned certain values of load and wind to each hour of the year (the forecasted values) and the important question to answer is how much diversion from these values can occur. Most of the load variability can be accurately predicted using a model as simple as a moving average model. As such, most of the load variations can be predicted by forecasts, incorporated into the planning of the system and deducted from the reserve requirements.

The question is what is the TSO's philosophy and approach to planning. One approach is to use a persistence model and assume that the load in the next hour is going to be the same as the last one and use reserves to cover any demand exceeding that value. In such a case statistical variability of load changes would be the logical tool to use to determine the reserves. The second approach is to produce a forecast using any available model and use reserves to cover divergence from the forecasted value, taking into account the variability. The second approach is much more sensible when there is an accurate forecast because it will lead to lower levels of reserve requirements. Reserves should be used to cover unexpected variability rather than total variability and in the case of accurate forecasts the variability is trimmed considerably. In the end in both cases the same amount of generation will be used but in the second case the amount of reserves required will be lower and more accurately predictable. This is especially important for a country like Estonia that doesn't have a lot of fast regulating units. However the second method requires availability of an accurate forecast, which isn't yet the case for Estonia. Also, it depends on the accuracy of the load forecast model which varies depending on its sophistication. As such, in the absence of a load forecast, total variability can be used if it isn't inappropriately high.

Finally, if 24 hour ahead is the time prior to which the reserves need to be committed, the forecast error's standard deviation is the only reliable measure since the variability of wind for data points 24 hours ahead is just too large to be used as a useful guidance for reserves.

As such, one of the most critical factors in this discussion is the time of reserve commitment. If reserves need to be deployed 24 hours ahead of time, taking under account even a highly erroneous forecast error is the optimal approach, while if it's on a per minute basis, taking under account historical statistical data is better.

To determine the regulation reserves, the first step is to calculate the net load variation. The net load variation standard deviation is given by the following formula (or simply the net load variation is calculated by the net load time series if that is available):

$$\sigma_{NL} = \sqrt{{\sigma_L}^2 + {\sigma_W}^2}$$

In the figure below the difference between load and net load for Western Denmark is presented. It can be seen that at certain times wind production is actually covering more than the load at that time and as such it has to be curtailed and down regulated or exported. It also shows that the load itself follows a somewhat easily predictable periodical pattern and as such one could argue that its variability is predictable to a high degree.

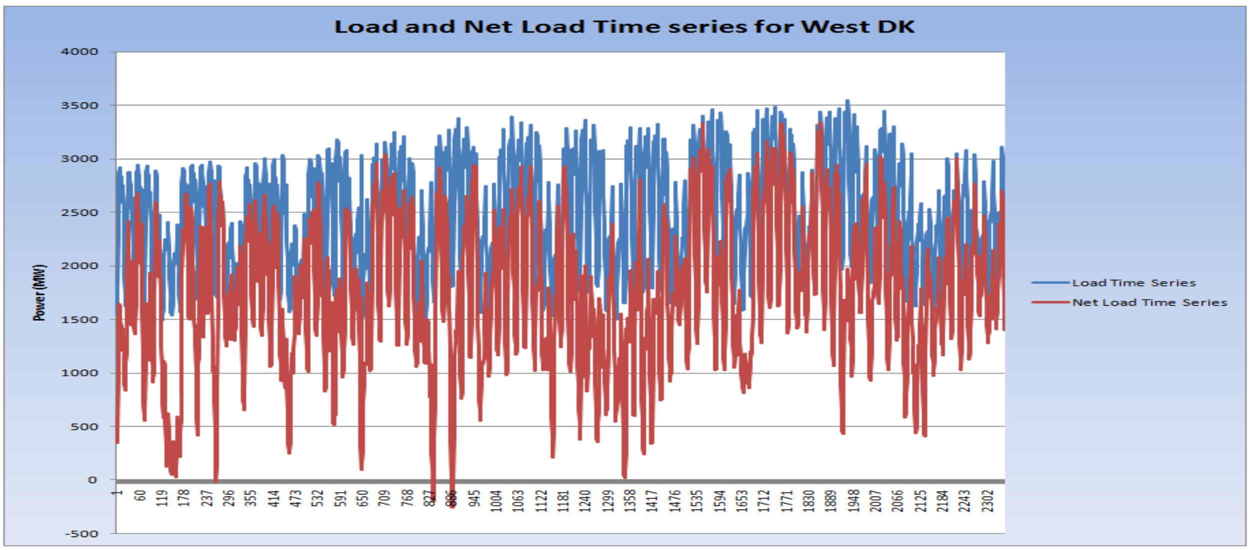

Figure 4.2: Net Load and Load for West DK, Sep. 2009-Jan. 2010

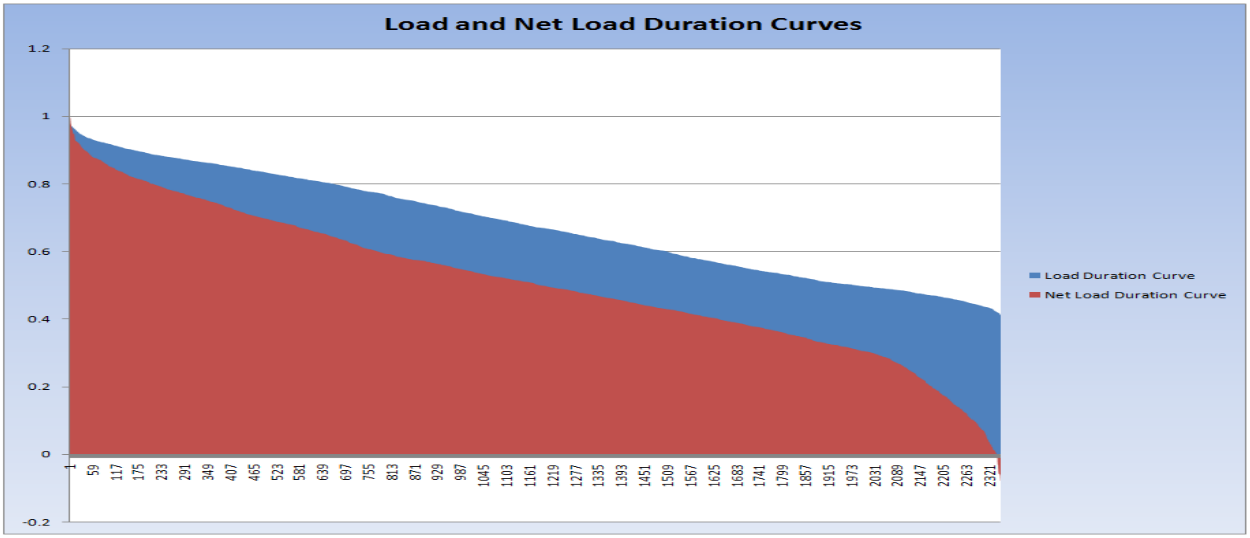

Figure 4.3: Load and Net Load Duration Curves in West DK, Sep. 2009-Jan. 2010

The duration curve for the load and net load can also be seen on figure 4.3 above. The next step is to calculate the amount of reserves required for different kind of reserves and circumstances. This depends on the number of statistical deviations and the degree of safety the TSO wishes to operate at. It is also a different number dependant on the type of reserves being discussed [15]. Three cases will be studied, the 1 minute reserves, the 1 hour reserves and the 24 hour reserves. The first has been chosen to give an indication of the regulation reserves. The other two cases are the time points at TSO's typically decide and revise reserve commitments.
Another classification of reserves could be according to season or according to levels of production. The first is useful because different seasons have different levels of wind power production (summer is not as productive as winter) and the second could be useful for more accurate reserve calculation. There is no point committing the same amount of reserves for a production level which on average has higher wind speed swings and one that is slightly less volatile. This is due to the fact that the power produced by a wind turbine is dependent on the cube of the wind speed and as such small variations in average wind speeds produce more important errors than those in low speeds (or high wind speeds because then wind power production halts).

Primary or Regulation Reserves

Regulation reserves were the first to be studied, as Elering provided time series (or forecasts of those) on a per minute basis of wind production and load consumption for 2008, 2010 and 2016. The regulation reserves will be determined by the methods described above, first as a multiple of the standard deviation (3 times) of the net load and then as the quantity of reserves that covers 99.7% of the net load changes. The comparison of those two methods will yield an estimate on how normally distributed net load variability is. Also, an effort will be made to estimate wind's contribution to those reserves.

To get the wind and load variability, the wind and load changes for each minute in the time series have to be calculated as following:

$$\Delta w = W_i - W_{i-1}$$

$$\Delta L = L_i - L_{i-1}$$

Then the standard deviation of the time series of wind and load changes is calculated. The net load deviation will be:

$$\sigma_{\Delta NL} = \sqrt{{\sigma_{\Delta L}}^2 + {\sigma_{\Delta W}}^2}$$

And the reserve level covering 99.7% of the cases should be:

$$R = 3 * \sigma_{\Delta NL}$$

Using the second method, the values that incorporate 99.7% of the observed net load changes are found. For 2008, 2010 and the 2016 (for the 1150 MW wind capacity scenario) time series incorporated here, the results for both methods can be seen in the following table:

Year	3σ	99.7% exceedence levels
2008 Regulation Reserves (MW)	3.82	3.11 (up), 2.62 (down)
2010 Regulation Reserves (MW)	5.37	5.47 (up), 5.23 (down)
2016 Regulation Reserves (MW)	21.50	23.71 (up), 23.52 (down)

Table 4.1: Regulation Reserves for different years in Estonia

It can be concluded that the amount of regulatory reserves are at each time quite low. The two methods provide similar results, showing that the net load change distribution on a per minute basis is almost a perfect normal distribution. The low amount of reserves required for frequency balancing purposes is due to the very small variation of wind and load on a per minute basis as well as the fact that wind is currently contributing to a very small amount of capacity in the Estonian system. The contingency requirement of having enough reserve to cover the biggest generator tripping can also satisfy the regulation reserve requirements. In 2016, where 1150 MW of wind capacity were assumed, the reserve requirement grew significantly, but obviously not enough to put a strain in the system. It would be interesting as such to see what part of the reserve requirement is due to wind and which one is due to load. This can be done by the following formula in this case [9]:

$$W_{res} = 3 * (\sigma_{NL} - \sigma_L)$$

And the results are shown in the following table:

Year	Increase in Reserves due to wind (MW)	% of reserves	Wind Capacity (MW)
2008	0.88	23.15%	65
2010	2.40	44.57%	170
2016	18.14	84.37%	1150

Table 4.2: Wind Contribution to frequency response reserves

Wind contribution to the regulation reserve is growing with increased wind penetration as it can be seen on table 3 above. This is because the actual load change deviation is assumed to not change over the years and has a particularly low value (~1 MW for all years) and as such increasing amounts of wind will require increasing amounts of reserves. However, even for the last scenario of 1150 MW of wind, the regulation reserve requirement is well below the actual contingency requirement, which is 350 MW for Estonia (the size of the Estlink connection to Finland). As such, even for large amounts of wind power it is assumed that the existing reserve requirements will be adequate to deal with frequency imbalances and similar to Energinet.dk's planning separate reserve for frequency regulation will not be required.

It must be noted though that the reserve should have a sufficient ramp up rate to deal with this kind of intermittency and for example for the 2016 scenario reserve units should be able to ramp up (or down) to 23 MW/min. This is a rather low requirement since the contingency reserve of 350 MW also needs to be activated at the same time frame as the regulation reserve, so this should not be an issue. This is of course a conservative approach since in reality reserve requirements might be even lower as the smoothing effect is very noticeable in a per minute basis and it's probable that the biggest normalized wind production changes observed in this case will not be noted in a system with higher wind penetration.

Hourly planning of reserves

In the hourly case, either the forecast error or the statistical variability of wind will be chosen to provide a better idea of the reserve requirements. The net variability will provide the TSO with information about the possible development of wind and load over the next hour according to historical statistical observations. Planning around this variability could be complemented with a good forecast so that the level of reserve doesn't increase unnecessarily. If a forecast that is more accurate than a persistence model for this time frame is available, it should be used instead, similar to the WPPT model shown in figure 3.1. However, this is not the case for Estonia. There is no reliable forecast (for wind or for load) and furthermore persistence is anyway shown to be almost as accurate as most wind power models for this time horizon [8], [9]. However there is a report incorporating a forecast that performs better than variability [15] and as such an assumption will be made that the forecast could decrease the error in wind predictability in the future.

There will be 4 different scenarios with 140 MW of wind (onshore, current situation), 750 MW of wind (onshore), 2300 MW of wind (2000 onshore, 300 offshore) and 3700 MW (2700 onshore, 1000 offshore), according partially to Elering's plans for expanding the wind power network. The factors that have to be taken under consideration are firstly the 'smoothing' effect from the wider spatial distribution of wind parks and secondarily the different variability of offshore wind parks to the onshore ones.

Proceeding with the methodology used for regulation reserves, a 'general' reserve level is calculated for the 1-hour planning. Table 4.3 below shows the results for the first scenario (current situation), where the two numbers calculated with the exceedence method are the down (negative) and up (positive) regulation respectively:

Wind capacity	3σ (MW)	4σ (MW)	99.7% exceedence (MW)	99.99% exceedence (MW)
140	145.47 MW	193.97 MW	-98.92/161.40	-148.00/187.09

Table 4.3: Reserves for the current situation

These reserves have to be deployed in an hour, so the relevant back up units should be able to ramp up and down to approximately 200 MW/hour if the TSO wants to cover 99.99% of the occurrences. It can be seen that the two methods provide slightly different results, which can be explained by the fact that the net load variability is not normally distributed but slightly shifted towards positive values (i.e. load tends to increase rather than decrease). The average change is still zero.

When looking to expand this table into the other cases that should be studied, the smoothing effect should be taken into account. However, this requires a lot of considerations. There is no established way of knowing how much this will affect wind production, as it works differently in different areas. For example Jutland, where wind turbines are spread over a much larger area than Estonia has pretty much the same variability standard deviation as Estonia [5], while the smaller spatial distribution of Baden-Wurttemberg yields a smaller standard deviation [11]. Also, it should be noted that any gain from expanding the network geographically comes from the increased spatial distribution and not from an increase in capacity in different locations. In Denmark-East onshore capacity has increased by 200 MW

since 2000, but in 2009 the variability of the wind was unchanged [5]. Unless the new wind turbines are placed in a different location with a considerable distance from the old, the variability gain from smoothing won't manifest. Finally, it should be noted that smoothing has decreasing gains. After approximately 300-500 km the large gains made from smoothing up to that point begin to diminish [13].
Since there is no way of knowing how much of the smoothing effect is already incorporated in the Estonian wind production, two scenarios will be made, assuming spatial distribution of wind turbines will lower wind variability's standard deviation to 2% and 3% respectively from the current 3.5% of the wind capacity status. This can also be attributed to better forecasts which will be used in the future instead of the persistence model for small time horizons.

For the offshore wind farms, it will be assumed that the same standard deviation as the one counted right now for the Kihnu site will persist in the future. According to the data provided by Elering, Kihnu wind production values will present a 6.23% deviation from the mean (for approximately 130 MW of installed capacity). A reason to keep the same deviation is that this is already an approximation and is low compared to similar figures for offshore Danish farms so it is assumed no further reduction should be required to accommodate for the smoothing effect.

Since no data is available for those increased capacities, the exceedence method results are calculated by determining the quintile function of a normal distribution with the characteristics desired (mean of zero and standard deviation according to the above) with the help of R, a software used for statistics. As such, the values of these results should only be treated as an indicator and not an exact calculation. The load is assumed to follow the same trend and distribution, so no changes are made to that. The results can be seen in table 4.4 below:

Wind Capacity (MW)	3σ reserves (MW)			4σ reserves (MW)			Exceedence reserves (MW)		
	σ_w=2%	σ_w =3%	σ_w =3.5%	σ_w=2%	σ_w=3%	σ_w=3.5 %	σ_w=2%	σ_w=3%	σ_w=3.5%
140	-	-	145	-	-	194	-	-	161
750	151	159	164	202	212	219	115	126	130
2300	195	237	260	260	316	347	152	182	207
3700	320	405	452	427	540	602	253	318	352

Table 4.4: 1-hour reserves for different scenarios of wind expansion in Estonia

As it can be seen, the 2 methods diverge considerably as wind capacity increases. This manifests the fact that the wind forecast error distribution diverges further from a normal distribution as the size of the wind reserve increases. However this is a useful tool for estimating the reserves and giving a general idea of their required level.

The level of reserves does not change considerably until large quantities of wind are incorporated into the system. It can be seen that even if the current capacity is quadrupled (750 MW) the reserve requirement only changes by 20 MW or so. However, as wind penetration increases, the level of reserves becomes significant and this is solely attributed to wind. In a similar way to the previous chapter, wind contribution to reserves is calculated and shown in table 4.5 for each case.

This confirms that for even 750 MW of onshore wind, most of the reserves are required for load variations and wind contribution to reserves becomes important only when approximately 2000 MW of wind are installed. As such, wind intermittency doesn't seem such a threatening feature and it seems with a minor commitment of an extra reserve power unit even large amounts of wind could be integrated into the system.

Wind Capacity (MW)	3σ method- Res. Increase due to Wind (MW)			4σ method-Res. Increase due to Wind (MW)			Exceedence Res. Increase due to Wind (MW)		
	σ_w=2%	σ_w =3%	σ_w =3.5%	σ_w=2%	σ_w=3%	σ_w=3.5%	σ_w=2%	σ_w=3%	σ_w=3.5%
140	-	-	1	-	-	2	-	-	14
750	7	15	20	9	20	27	7	15	20
2300	51	93	116	68	124	155	51	93	116
3700	176	261	308	234	348	410	176	261	308

Table 4.5: Contribution of Wind to Reserve Requirement

Of course the metric used above is quite general and doesn't take into account a lot of factors that could ease the reserve burden as well. Reserves don't need to be the same for every season of the year, as the load and wind levels, and consequently load and wind variability could be decreased for some specific months. Calculating wind and load variability separately for the four seasons of the year would aid a lot in cutting down excess reserve capacity. Below, a comparison of the standard deviation of the wind, load and net load depending on the season is shown. Wind variability is increased slightly during the winter and load variability (and hence net load one too) is decreased a lot during the summer.

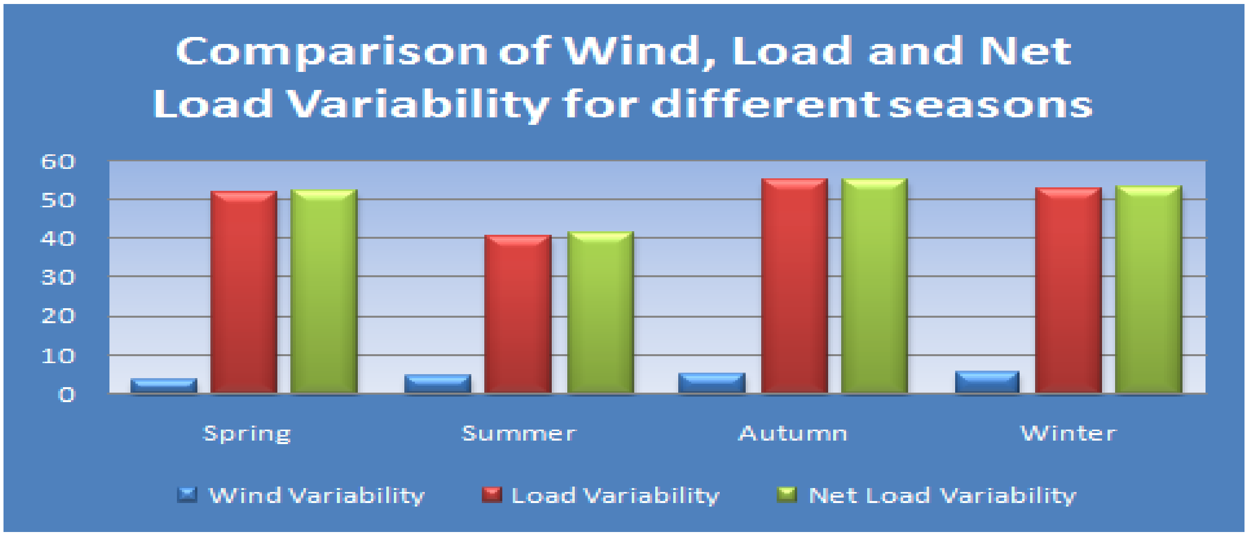

Figure 4.4: Standard Deviation of wind, load and net load for the different seasons of the year, Estonia 2007-2009

Another interesting approach would be to differentiate the level of reserves according to the amount of load consumption and wind power production at each hour. This can lead to a more exact value of reserves required (as seen previously wind variability is not at all the same for hours where the wind production is at 0.2 rated and hours that it is at 0.8 rated) lessening the burden on the system. However this approach has its limits since it would require that reserves could be increased within the hour depending on the production levels of wind and this is just not very feasible for some reserve units which have very slow start up times and need to be committed more hours ahead. As such this approach will only be used when planning for reserves 24 hours ahead.

For the seasonal data, the same methods as previously were used and the results for three and four standard deviations are shown below for each season and standard deviation hypothesis. Since using only one year isn't conclusive, data from 2007 up to 2009 were used to ensure sufficient sample size for the calculations. It has to be noted though that the wind variability was becoming more similar for the different seasons at 2009 when the installed capacity was increased somewhat and as such overall variability decreased.

Method	Spring	Summer	Autumn	Winter
3σ (140 MW wind)	154 MW	149 MW	167 MW	186 MW
4σ (140 MW wind)	205 MW	199 MW	223 MW	249 MW

Table 4.6: Seasons reserves for Estonian power system, 2007-2009

Even if summer presents a somewhat larger variability, reserves are lower then as the net load is on average lower over this season. As it can be seen this can make a difference in reserve planning as there is a difference of as much as 50 MW in required reserves between the summer and the winter. This difference will be bigger in future scenarios so the TSO is advised to at least split reserves based on season if not even more detailed. The exceedence method is not tried out for this calculation as the sample size is getting too small and fractured in different years for this method to be applicable.

Finally, it should be obvious that the ramping rates correspond to the reserve level/hour. For example for summer, units must be able to ramp up to 150 MW per hour if required, according to the 3σ method.

24 hour ahead reserve planning

For this time frame, which is usually when unit commitment schedules are produced trying to account for wind power through forecasts is the best idea. The standard deviation of wind variability 24 hours ahead for Estonia for example is approximately 40 MW with 140 MW of installed capacity while the forecast has a standard deviation of only 13 MW. As such it is a superior and more accurate way of committing units and planning reserves 24 hours ahead. Alternatively, it can be said that the persistence model suffers greatly from prolonging the time horizon while forecasts become significantly more accurate than persistence.

The same techniques that were previously used will be performed here, only this time it will be the standard deviation of the forecast taken into account instead of the wind variability. The scenarios for wind capacity will be the same ones as previously, but this time it will be assumed that the current forecast will be improved to the levels of German/Danish forecasts, yielding a root-mean square error of 8-10% instead of the current 14% (and the corresponding decreases in forecast error deviation and marginal absolute error). Additionally, the effects of 'smoothing' on the forecast error are better documented and accessible [13]. There is no load forecast for the Estonian system; as such, the load variability will be used again. Studies on the subject of load forecasts suggest the results wouldn't be much different if a forecast was used [16], [17].

The results for the four scenarios similar to the ones previously discussed are shown below (σ_w is now the forecasts error's standard deviation). 4σ results are not included because the results are high enough without it (distribution is not normal anyway, see below):

Wind Capacity (MW)	**3σ method Reserves (MW)**			**Exceedence Reserves (MW)**		
	σ_w=5%	σ_w =10%	σ_w =14%	σ_w=5%	σ_w=10%	σ_w=14%
140	-	-	141	-	-	58/-88
750	183	267	344	97/-185	163/-251	222/-310
2300	337	619	847	143/-379	362/-598	539/-774
3700	466	842	1148	202/-520	494/-812	731/-1049

Table 4.7: 24 hour ahead reserve planning under different scenarios for wind capacity

The distribution of the forecast error for the Estonian system is somewhat different from a normal distribution with a mean of zero, as seen in figure 4.5 below. It is shifted to the right considerably (actual production is usually higher than the forecast). The same can be observed for the Danish forecast, although it looks more like a normal distribution shifted to the right (mean=0.1 of rated output). As it can be seen, the forecast error is almost never more than 0.2 of the rated capacity (~22 MW in the Estonian case) for the up regulating case. Since the distribution doesn't have a mean of zero, it makes more sense to take the exceedence levels into account rather than the 3σ measurements.

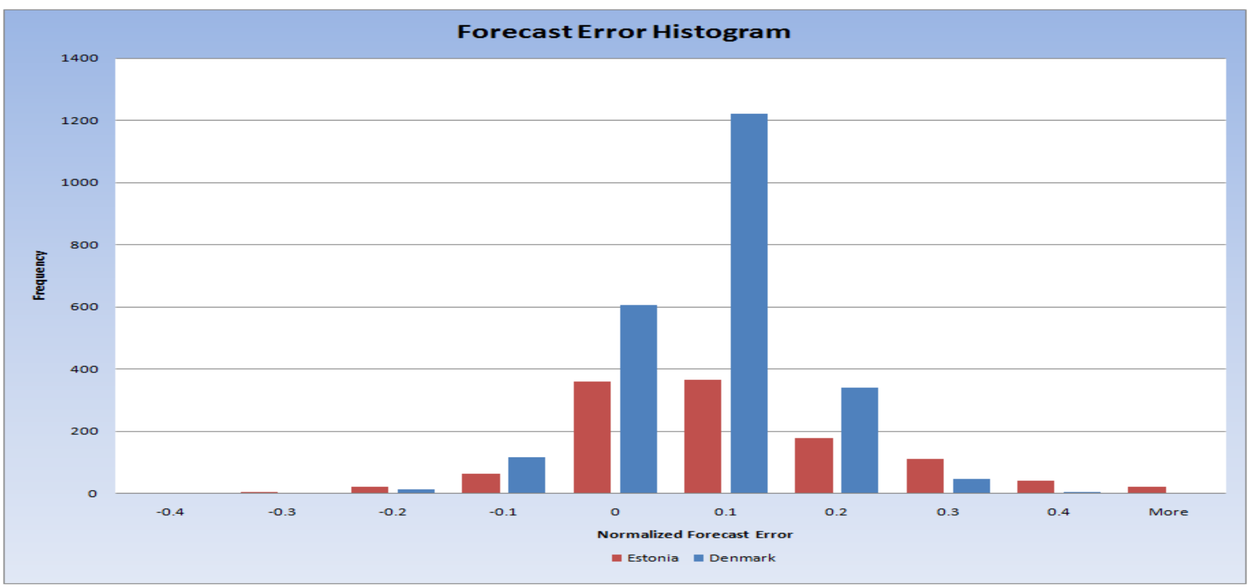

Figure 4.5: Normalized forecast error distribution for Denmark and Estonia

A seasonal analysis cannot be accurately made due to the lack of data, since most of the forecast data is available only for a limited amount of time. However it is also interesting to try and relate forecast error and production levels. As shown in figure 3.6 for the German case, forecasts errors are indeed different for various levels of production. It is interesting to see the same thing for the Estonian case. Below, the association between the forecast error and the level of production is shown for the Estonian case. The black line shows the average forecast error for production while the bars indicate where the first and third quintiles of wind power forecast error are for that level of production. It can be clearly seen that the error is getting bigger for the larger values of wind power.

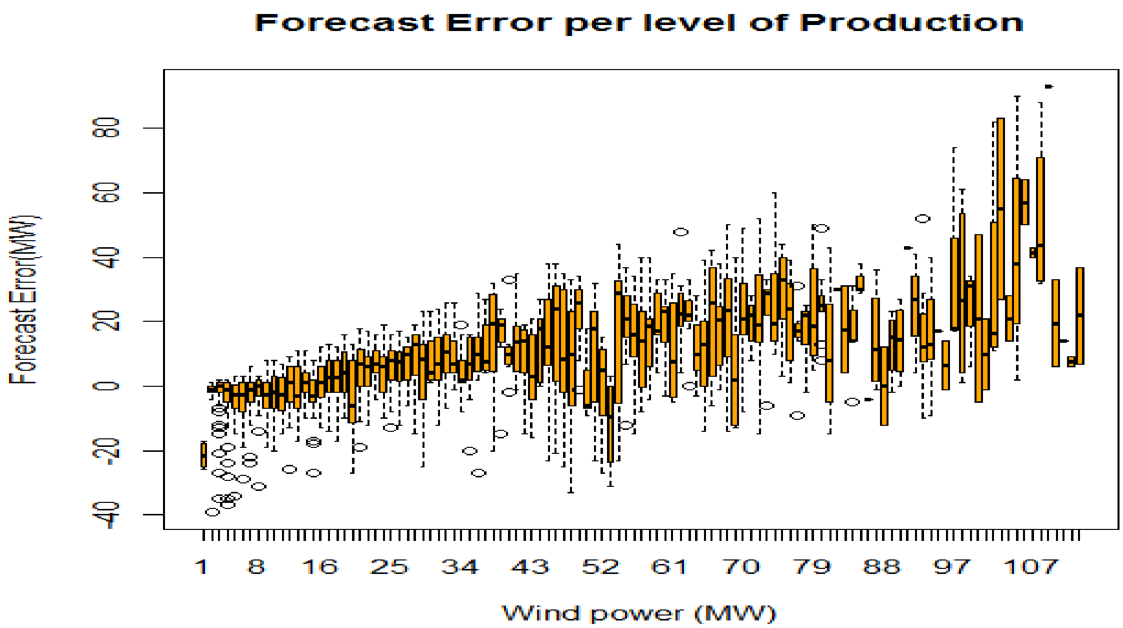

Figure 4.6: Plot of forecast errors compared to levels of wind production

Grouping the data so that a conclusion can be reached, the standard deviation of the forecast error for four intervals of production is shown in figure 4.7 below:

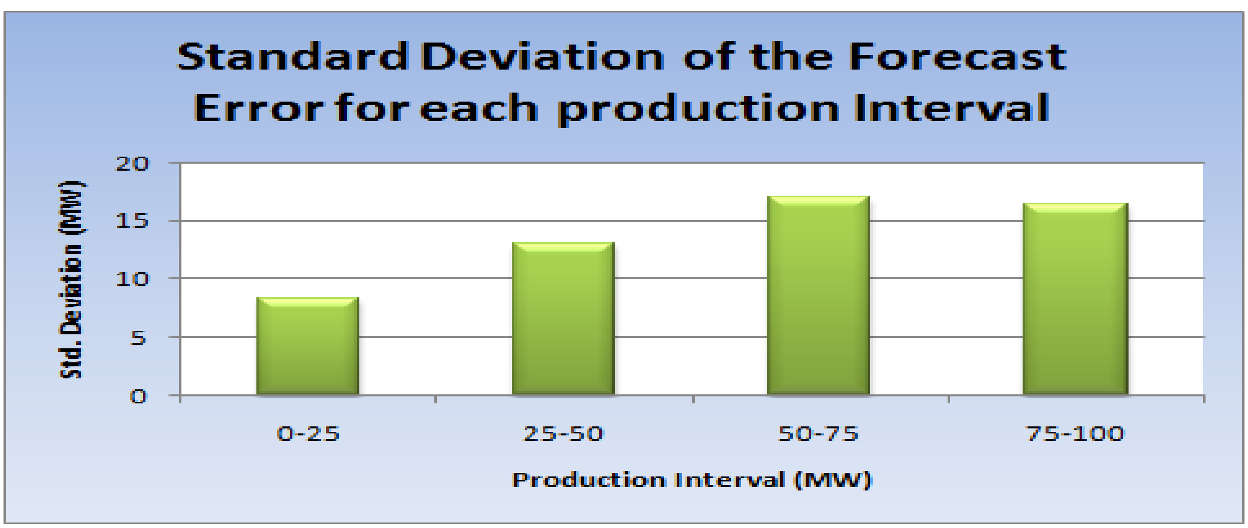

Figure 4.7: Std. deviation of forecast error for each wind production interval

As it can be seen, if the level of wind is closer to the first quintile then lower reserves are required because the forecast error doesn't vary as much as when the wind turbine is operating higher than the capacity factor (approximately above 26% for Estonia). Since this is the most relevant mode of operation (the majority of measurements lie in the first quintile) the reserve requirement could be lowered if wind is predicted to stay within the first quintile range for the following day. It would be expected that forecast errors would decrease for the last quintile, in accordance with the form of the wind turbines' power curve. This is not happening simply because these wind turbines are not currently reaching their maximum output (around 130 MW) but only go as fast as approximately 100-110 MW. As an example, reserves will be recalculated for the first quintile and compared with the general case of table 4.8, reducing the forecast error's range for the first quintile accordingly:

Wind Capacity (MW)	Exceedence Reserves, first quintile (MW)			Exceedence Reserves, 'general case' (MW)		
	σ_w=3%	σ_w=5%	σ_w=7.3%	σ_w=5%	σ_w=10%	σ_w=14%
140	-	-	58/-52	-	-	58/-88
750	134/-120	152/-138	179/-165	97/-185	163/-251	222/-310
2300	205/-167	282/-244	381/-344	143/-379	362/-598	539/-774
3700	287/-236	387/-337	519/-469	202/-520	494/-812	731/-1049

Table 4.8: Exceedence Reserves comparison between general case and low wind production case

As it is obvious, reserve requirements have decreased noticeably in most cases but not in all, because the distribution for the first quintile is skewed on the other direction than the general one (forecast is more than actual for the first quintile on average while it is less than the actual production on the whole distribution). In any case, this shows that there are plenty of situations where reserves could be reduced considerably if the TSO is aware of the actual level of production for the following hours/day.

As an example, reserves were calculated in a similar way to table 4.8 and figure 4.8 was constructed. It shows how the reserve level increase only due to wind would look like in the case of some hours in Estonia in 2009 compared to the actual wind production (wind time series are provided by Elering):

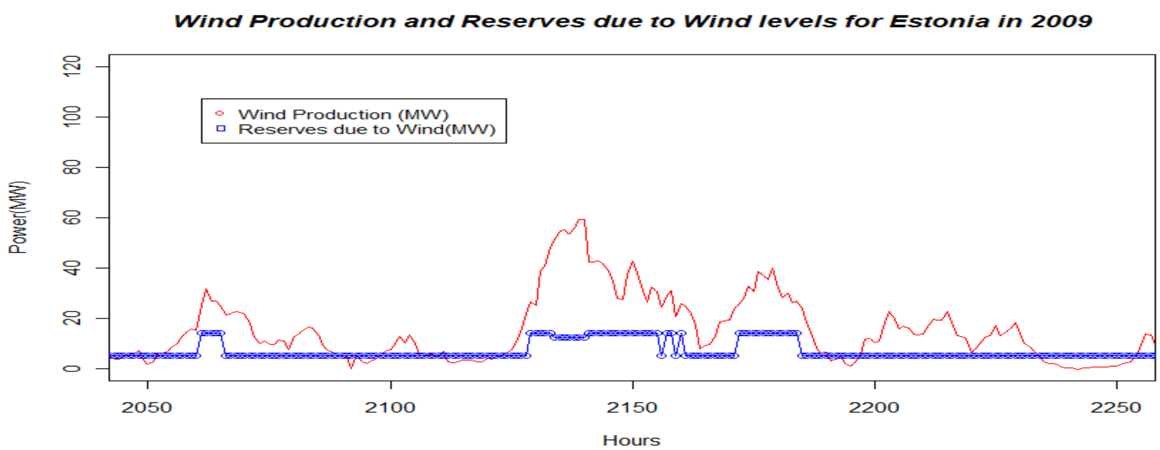

Figure 4.8: Reserve increase due to wind compared with wind production

It can be seen that sometimes the reserve levels exceed the wind production but this is only because the reserve levels are averaged over a quartile. The TSO could further decrease reserve levels at this time. Another alternative would be the development of a quadratic function that followed reserve development due to wind increase in relation to wind, but for the small amounts of reserves discussed here (~5-15 MW) this is unnecessary).

It should be noted that these numbers are estimations and guidelines for the reserves and models like those belonging to Energinet.dk comparing historical data of wind speeds, reserve requirements and load variability will prove to be more accurate.

Another note of importance is the actual amount of reserves for each time window could be determined by taking under consideration the reserves for the previous window. For example for the 500 MW case and a low standard variation of forecast error/variability, any of the 151 MW of the 1 hour reserves that are in excess can be used for fulfilling the goals set by the 24 hour ahead plan and similarly any unused regulation reserves could be used in the 1 hour time frame [18].

Reserve Calculation for the Estonian case

In order to assess the magnitude of the reserve requirement and whether this was met through solving the optimal dispatch problem, a method similar to the above was devised to come up with a reserve time-series, corresponding to the load and wind time series as generated through BALMOREL.
The first step was assessing what is the required reserve for a particular level of wind power and load. Assigning an 'overall' or 'general' level of reserves is not satisfactory, since as shown previously wind and load fluctuations are different for various levels of production/consumption. As such, similar to the German example show above, wind and load were broken down into five intervals whose standard deviation and statistical quantities would determine the level of reserves. The reason for choosing five intervals is accuracy versus statistical size. While a higher number of intervals would pinpoint the reserve requirements more accurately, there was not a large enough sample size to extract reliable statistical data for a higher number of intervals.

The method to calculate the height of reserves is the 3σ method described previously which incorporates 99.7% of all possible outcomes and as such is assumed to provide sufficient reserves for even some quite extreme occurrences. As such, according to the previously mentioned methodology, the reserve level for each interval was assumed to be calculated through the following formula:

$$Res = 3 * \sqrt{\sigma_w^2 + \sigma_l^2}$$

The question was which values would be accurate for the standard deviation of the wind and load for various scenarios generated by BALMOREL for 2013 and 2016. The Estonian current forecasting errors could not be taken into account, as they were considered too large and likely to improve significantly in the future. As such, the same kind of analysis was conducted for Germany and Jylland and the results for each interval are presented in the table and figure below, where the German results have been assigned to the cases corresponding to 2013 and the Danish ones in the cases corresponding to 2016:

Intervals of wind production (p.u.)	**0-0.2**	**0.2-0.4**	**0.4-0.6**	**0.6-0.8**	**0.8-1.0**
Jylland-Std. Dev.	34.68	52.00	50.85	55.44	28.81
Jylland- Norm. Std. Dev.	0.036	0.055451	0.054223	0.059118	0.030721
Baden-Std. Dev.	57.92	90.09	81.93	65.87	20.06
Baden-N. Std. Dev.	0.062	0.096	0.087	0.070	0.021
Maximum wind capacity			900 MW		

Table 4.9: Std. Deviation for Wind Intervals in the 900 Limited Market Case Scenario developed by BALMOREL

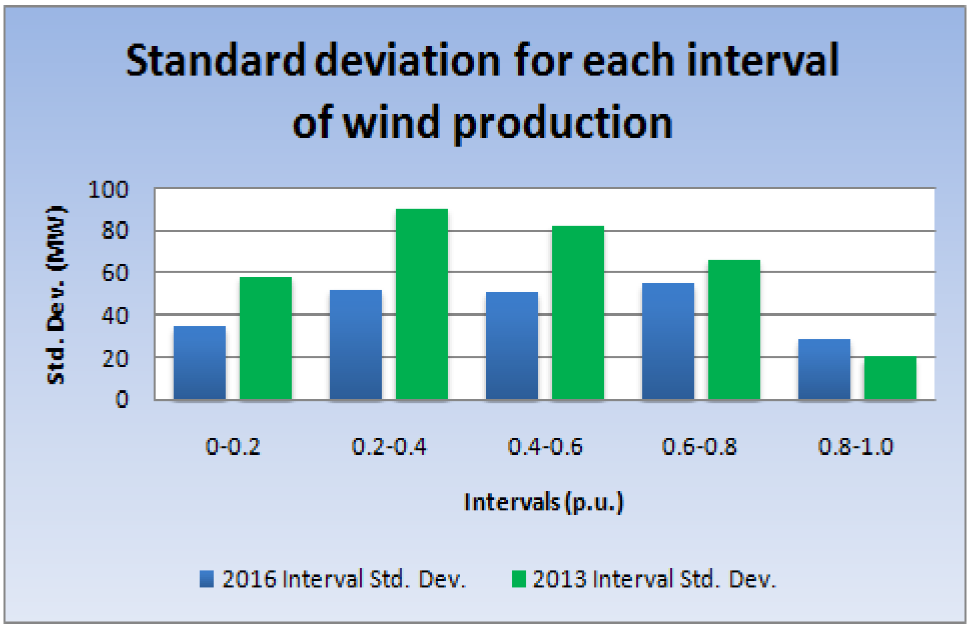

Figure 4.9: Standard Deviation for different wind production intervals

The standard deviations were calculated with a capacity of 900 MW in mind, as is the case for half of the scenarios involving wind integration in Estonia. It was decided to assume the standard deviations calculated in the Baden area would be used for the 2013 analysis, assuming an overall MAE of 10% while the Jylland results would be used for the 2016 case assuming an overall 6% MAE.

The load deviations were assumed to be the same as in the persistence case, as load forecasts can be quite accurate and reliable. Since the standard deviations of load and wind based on the current level of production were known, it was possible to calculate the reserves required for each hour. This was done and as an example, in the figure below the time series of wind, overall reserves and unassigned capacity (mostly free transmission capacity from Estlink) by BALMOREL are shown:

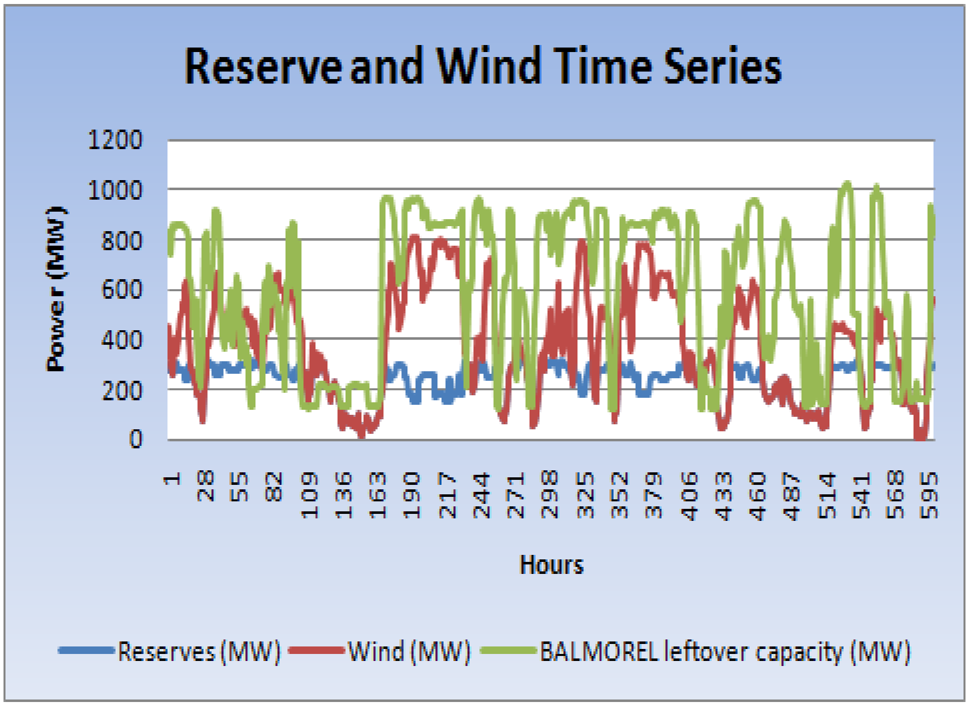

Figure 4.10: Reserve, wind and BALMOREL leftover capacity time series for a 2013, 900 MW wind Estonia scenario

The program prefers to lower the capacity of the thermal plants and primarily not to use the interconnection as long as it can serve the system needs using as much wind power as possible. That is the reason high wind power correlates well with high unassigned capacity. In the figure below, the reserves allocated by the 3σ method are deducted from the BALMOREL leftover capacity that can be ramped up within at most one hour :

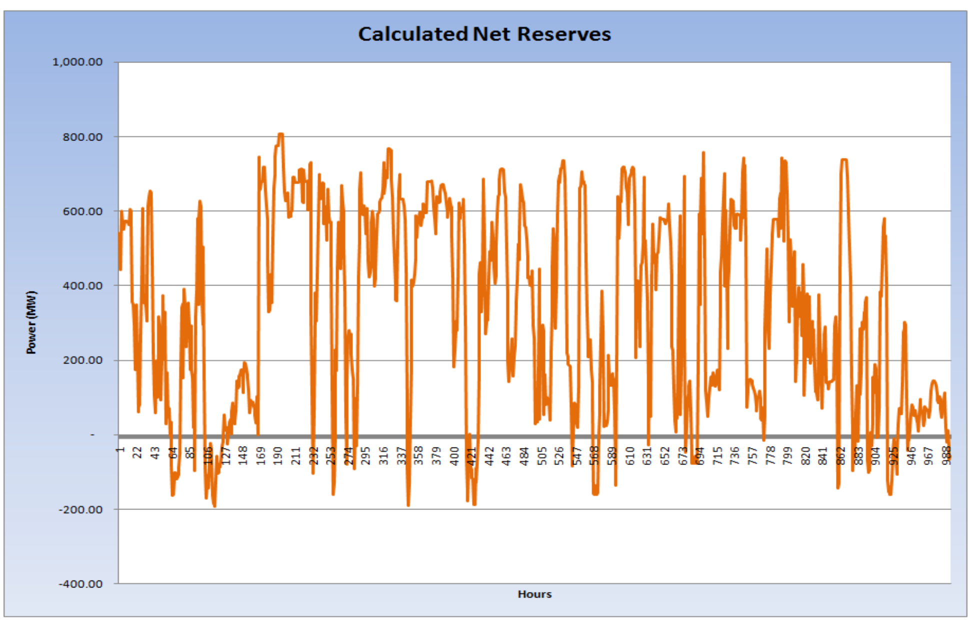

Figure 4.11: BALMOREL leftover capacity minus reserves calculated by the 3σ method, Estonia 2013-900 MW wind scenario

This shows that for most cases, further resource allocation is not actually required since there is sufficient backup capacity available within an hour to cover any unexpected fluctuations. However there are cases where reserves are lacking and this could be worrying. The Estonian units are on average slow to start up and unless they are committed already, fluctuations that are big could unbalance the system. However it should be reminded that this reserve calculation is meant to cover 99.7% of possible outcomes and in combination with the low amount of hours for which reserves are not enough means that an unbalance is not quite likely. Furthermore, this forecast error calculations are based on a 12-36 hour ahead prediction. If the time window is narrowed down to one hour, previous figures show that forecast errors are reduced drastically and the standard deviation of the net load is not expected to vary as much, reducing reserve requirements.

Finally, it should be noted that this is an issue with the 2013 Estonian system. In 2016, the addition of a second interconnection line (Estlink 2) to Finland with the potential to transmit almost instantaneously 1000 MW of power (compared to 350 MW for 2013) means that this image will be significantly altered and the BALMOREL leftover capacity would be sufficient for the reserve planning, making the integration of large wind quantities smooth and unproblematic.

In the figures 4.12 and 4.13 shown below, the total unused capacity of the power plants that operate in the Estonian system and can be ramped up within an hour according to the optimization solution is shown and compared to the level of reserves required as calculated by the previously discussed methods. The results are shown for a week. As it can be seen the addition of the second transmission line in 2016 alleviates any reserve concerns as the transmission capabilities of Estlink 2 should cover any unexpected divergence from the forecast error. However it should be noted that this will lead to an increase of the contingency reserve, since n-1 will need to cover now the size of the Finnish-Estonian interconnection. It is a concern since according to Elering, they are obliged by their contracts with other TSO’s to keep their contingency and regulation reserves separate and as such this will lead to an overall high amount of reserves.

It should be also remarked that the interconnections to Russia and the other Baltics were not considered in this scenario, as the Estonian TSO considers them inflexible and unavailable to provide regulating capacity in times of emergency. However future agreements could augment their role in reserve planning.

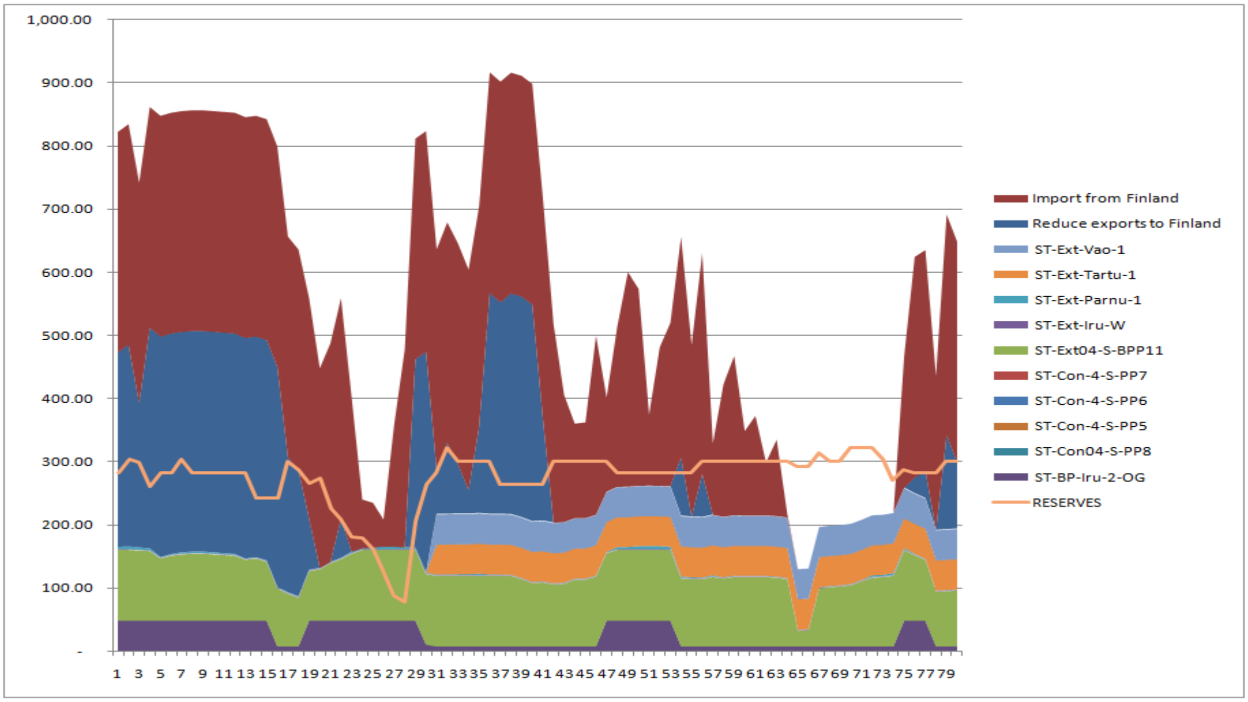

Figure 4.12: Results produced by BALMOREL for reserves compared to reserves calculated with the 3σ method, 2013

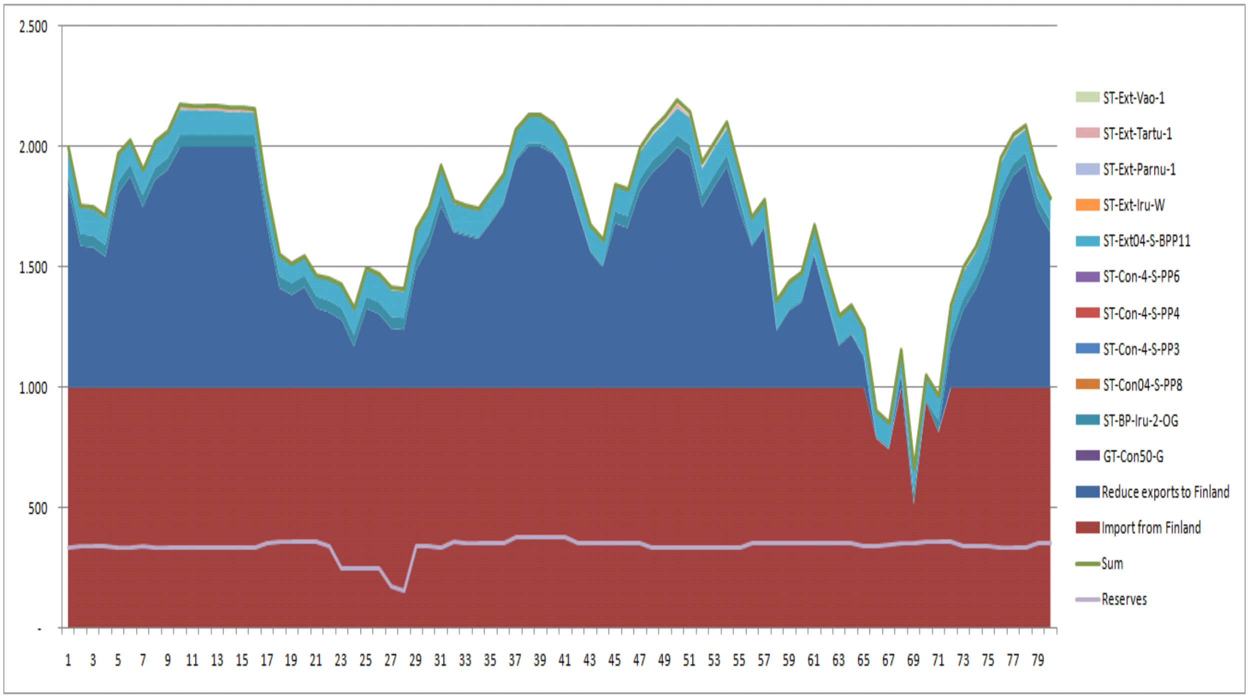

Figure 4.13: Results produced by BALMOREL for reserves compared to reserves calculated with the 3σ method. 2016

The above graphs show the results only from one week and can thus be misleading. If, similar to figure 4.11 the calculated reserves are deducted from the unused capacity a much clearer picture will emerge, as shown in figure 4.14 below:

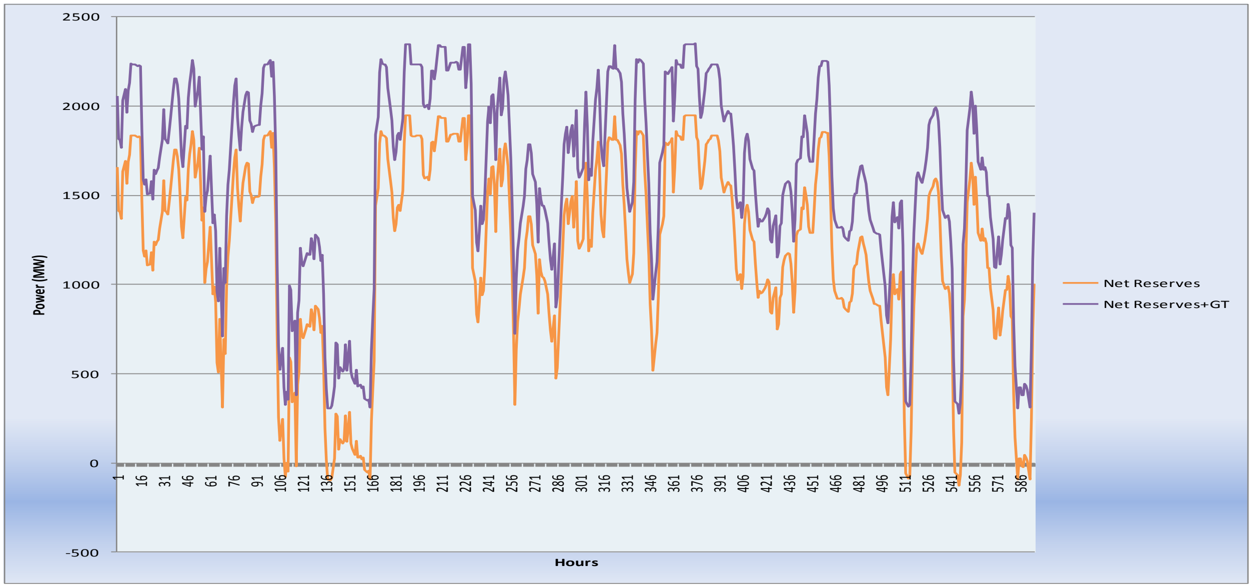

Figure 4.14: Net Reserves (Calculated reserves minus BALMOREL unused capacity) for 2016, with and without a 400 MW gas turbine

The above graphs can show that there are still occasions, like when the Estlink 2 connection is already committed that the reserves are not sufficient. However this quickly changes if the plans of Elering to build a 400 MW gas turbine with a start up time of 10 minutes (and 10 minutes further to reach full capacity) come to fruition. However it should be noted that the size of that power plant may be excessive and unnecessary and that a smaller gas based power plant could have the same effect.

4.3 Interconnections, ramp up and start up rates in the Estonian system

An important aspect of any system is how fast it is possible to ramp up to cover for any possible contingencies or sudden changes in consumption/production. The existence of fast start up stations that can ramp up their output quickly is a benefit for any power system that might face disturbances. Additionally, the planning is greatly facilitated by knowing what kind of choices the TSO can make. If a system consists of slow start and ramp up plants, the TSO would know that planning 24 hours ahead is a good approach so that the system doesn't face any unpredictable disturbances that might offset its balance. Furthermore, every system has a possibility to import or export some power through the use of interconnectors. However those are not always available, depending on the situation in neighboring systems or their availability rates. As such, two cases will be studied; one involving the ramping rates of the system with interconnectors and one without.

In the interconnection case, it will be assumed the EstLink interconnection is available and in the island case no interconnections will be taken into consideration.

Interconnections are particularly important because the amount of reserves calculated previously could be fulfilled by the capacity provided by them. Estonia has interconnections both to Finland (Estlink 1 and soon another Estlink connection) and to the Baltic States and Russia which could cover a large amount of the reserve requirements. It would mean the system would not require the operation of any additional thermal units as reserve for wind during several hours (and possibly benefits from exporting the wind instead of curtailing it could be acquired depending on the power market).

For the island case, the case scenario is that all units are operating on their minimal operating capacity and what is measured is how long it would take the system to reach peak supply when starting from the minimal operating capacity. This is not the worst scenario, as all units being online means a much faster response time than if the relatively slow Estonian units were to be totally shut down. The results are shown in figure 4.15 below:

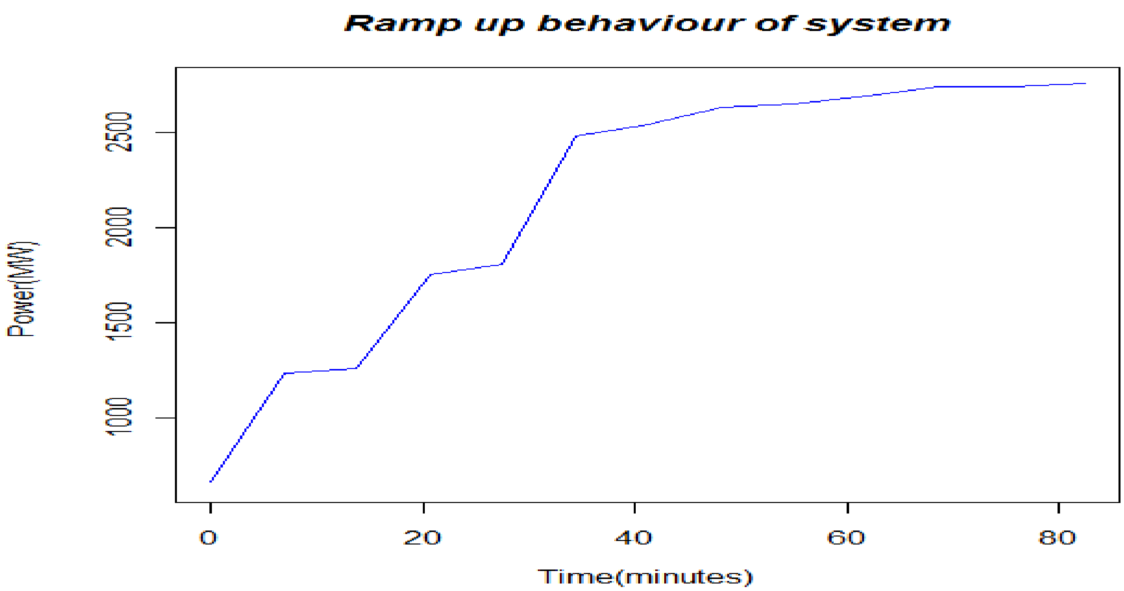

Figure 4.15: Ramp up rate of power system for Island case with all units running on minimal capacity, Estonia 2015

As it can be seen, from the minimal operating capacity of 665 MW it will take the system 15 minutes to reach maximum load (1550 MW) and around 80 minutes to reach maximum capacity, which is however not needed for any load value observed today. This yields a ramp rate of 900 MW/15 minutes or 60 MW/min on average and is mostly attributed to the fast gas turbine units expected to be installed between 2013 and 2015. However much of this capacity (particularly the gas turbines) is not currently available and as such the actual system is somewhat slower and requires almost 30 minutes instead of 15 to reach the peak load value. As such if more power is available to be acquired through the use of interconnections this could be an improvement. However this relies on whether there is an excess of power in the other regions or if there are units there faster than the Estonian ones that can ramp up their output quickly and transmit power to Estonia (including expected losses). There is also the issue of cost and objectives since importing some other country's excess of wind could be less costly than starting up a thermal unit and more environmentally friendly. Finland and the other Baltic states are expected to develop a rather large amount of aggregated wind capacity in the future.

Taking the interconnections into account, their effect is shifting the previous curve up if the full capacity of the transmission lines is available. That would mean 350 MW from Estlink and 600 MW from Russia, which along with every power station in Estonia operating at minimum capacity would cover all of

Estonia's demand at any time insofar. In another case where Estlink is the only available transmission line for example, the effect will be less noticeable but will mean that reaching peak load values could take less than 10 minutes. The revised figures are shown below for the case where only Estlink is included:

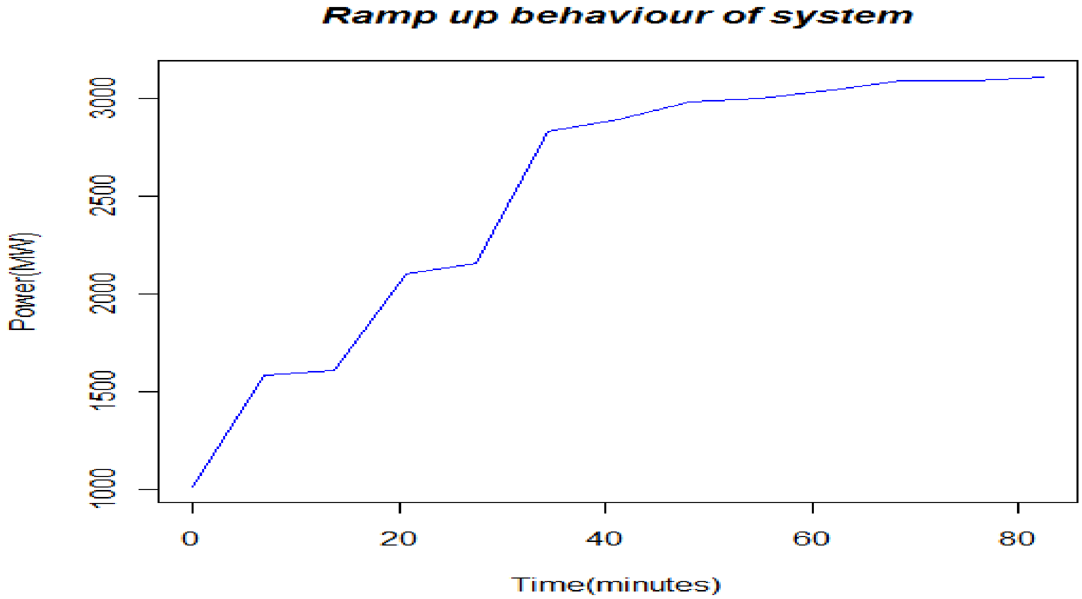

Figure 4.16: Ramp up rates when Estlink is included

The image is similar, as it was assumed the 350 MW of Estlink are readily available and no ramping up of power units in Finland had to take place. In such a case the peak load value is reached within 8 minutes, assuming every Estonian unit is operating at minimal capacity (which would very rarely be the case). Without the gas turbine units expected to be operating by 2015 this figure would raise to 10 minutes.

Finally a case is made for when some of the units in Estonia are operating at full output while others are shut down and 1 unit (Eesti New) is operating at minimum capacity while total production starts at 1255 MW. The gas turbines unit will not be included in this case. It is assumed Estlink is only partially included (150 MW option). This case is interesting because it shows how ramping can happen in a case where 200-300 MW of reserves are required, as is the case in many of the calculations conducted in the previous chapter. The ramp characteristics of this system are shown in the figure below:

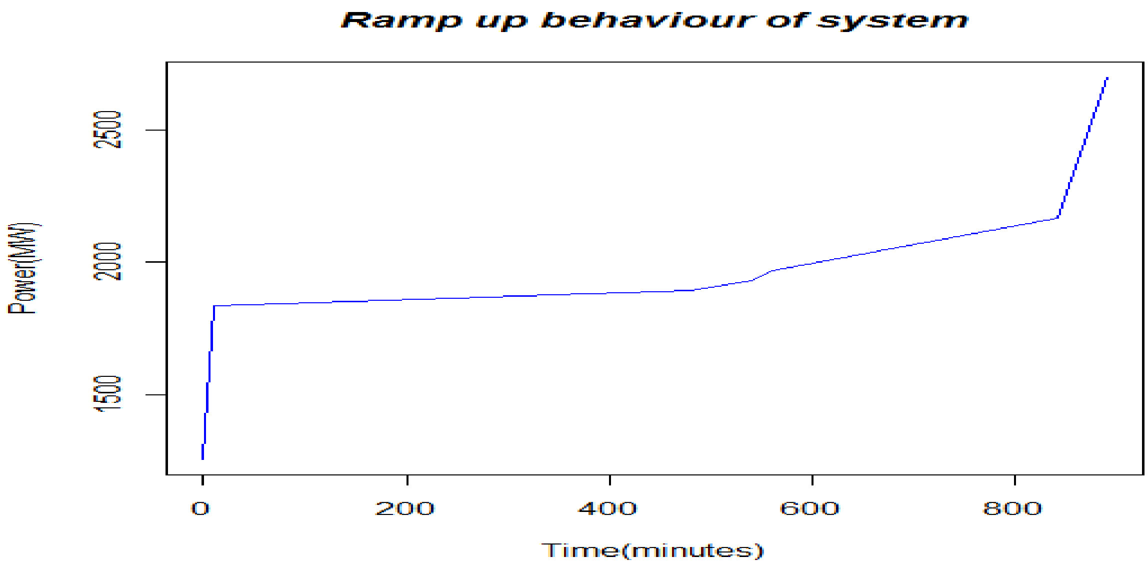

Figure 4.17 Ramp up Characteristics of case with start-up requirements

As it can be seen ramping up from 1200 MW to 1550 which is the peak load can be done effortlessly in a few minutes, however if the transmission line is inoperable or the new Eesti plant is not included the ramping rate of the system would suffer. The above graph shows that the Estonian power plants have slow start up times and cannot respond sufficiently to very large fluctuations in supply or demand unless they are already operating at minimum capacity. This however has problematic economic consequences as operation costs could grow out of control. What this shows is how essential accurate planning and forecast is, as even if the Estonian system has lots of overcapacity it can be strained to respond to sudden imbalances since it has no quick response units.

Conclusions

This report has dealt with the issues of capacity credit, wind power forecasting and associated reserve planning for the Estonian power system in order to examine the possibilities of extended wind power integration into it.

On the first topic, expectedly wind power did not offer significant (even if still not negligible) contributions to capacity credit. This was due to significant amounts of existing overcapacity in the system which essentially diminish greatly the probability that load will be lost at any time. As was shown at the end of the relevant chapter, a possible increase in load or a decrease of thermal capacity will lead to wind markedly augmenting its contribution. The different methodologies provided diverging results but the results acquired by the three methodologies involving the calculation of loss of load probability followed the same trend when wind or demand was increased, showing that wind will continue to provide small benefits to system adequacy as it expands. The final and simpler methodology gave more unreliable results which depended a lot on arbitrary factors like the level of reliability chosen by the TSO. When wind time series are provided like in this case, it would be advisable to follow a LOLP based methodology.

On the second topic, forecast systems operating in Denmark, Germany and Estonia were compared. It was shown that changes in the Estonian forecast to converge to the precision of its Danish and German counterparts would greatly benefit wind power predictability and the TSO's ability to plan ahead. Furthermore, one of the important conclusions was that the wind predictability can decrease quite a lot when wind farms are installed in wide areas and as wind output increases. This so-called 'smoothing' effect's impact on wind forecasting should be noted for any future expansions of the Estonian system.

Finally, the reserve planning arrangements that need to be made due to increased wind penetrations were examined. Uncertainties in load forecasting already oblige the TSO to keep a certain level of reserves active (along with contingencies). Wind unpredictability compounds this situation. The derived results showed that reserve levels will not increase significantly until quite high levels of wind penetration (~2000 MW). Even at that point, careful examination of wind unpredictability's variations across seasons and levels of wind production can allow the Estonian TSO to maintain a reasonable level of reserves. What was problematic though was the inability of current Estonian units to start up rapidly in response to swift (even if rare) wind power changes, but the plans of the Estonian TSO to complement wind power production with new natural gas plants with fast start up times and an extension of the interconnection to Finland will help to significantly alleviate any potential problem.

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